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NATURAL GAS REGULATION STUDY

PREPARED BY THE
CONGRESSIONAL RESEARCH SERVICE
AND THE
NATIONAL REGULATORY RESEARCH INSTITUTE
FOR THE USE OF THE
SUBCOMMITTEE ON FOSSIL AND SYNTHETIC FUELS
OF THE
COMMITTEE ON ENERGY AND COMMERCE
U.S. HOUSE OF REPRESENTATIVES

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SUBCOMMITTEE ON FOSSIL AND
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COMMITTEE ON ENERGY AND COMMERCE
WASHINGTON, D.C. 20515

May 25, 1982

The Honorable John D. Dingell
Chairman, Energy and Commerce Committee
U.S. House of Representatives
Washington, DC 20515

Dear Mr. Chairman:

In June of last year, I requested that the Congressional Research Service (CRS) undertake a study of the underlying basis for the current regulation of the natural gas industry in this country and whether other options might exist for regulating this industry.

I felt that we were in need of a document that set forth a good analysis of the industry as it is, and as it has developed, to aid us in any consideration of natural gas issues.

The CRS has completed this study, carrying out much of the work and analysis in-house, while contracting with the National Regulatory Research Institute to prepare that portion of the study which deals with the regulatory activities of the individual states.

It is clear from the study that the history of the industry has had a great deal to do with both its structure and the manner in which it is regulated. The study also provides a very useful preliminary analysis of a number of areas that this Subcommittee hopes to explore in some detail as the industry moves closer to the partial wellhead deregulation date of 1985 established in NGPA. It does not, however, attempt to discuss all of the questions that have been raised regarding the industry or the NGPA.

The study includes a number of useful discussions:

(1) A very readable synopsis of the structure of the natural gas industry, from the production of gas at the wellhead to its sale at the retail level;

(2) A summary of the Federal regulatory structure which governs the natural gas industry, and an explanation of how that structure affects interstate pipeline companies and local distribution companies;

(3) A summary description of the provisions of the NGPA, and of many of the views that have been put forward in the last two years on what the impacts of the NGPA have been;

(4) Identification of some of the major legal issues raised by the termination of Federal control of wellhead prices (as envisioned in NGPA), with respect to authorities the states will be able to exercise in the absence of Federal controls;

(5) An overview of the technology of transporting natural gas, and a discussion of how the evolution of that technology has limited the marketing of gas, has affected the regulatory structure which exists today, and has influenced some of the business practices which have evolved in the industry;

(6) A summary of the organization and economics of the interstate pipeline system in this country;

(7) A summary of the differences between a utility method of regulation (as currently in place) and a common carrier method of regulation for the interstate pipeline companies, and an outline of how the utility method could be phased out over a transition period; and

(8) In the Appendix on state authorities, a summary of the extent of authority held by the states to regulate the natural gas industry at the state level; a description of the major rate-making issues now receiving attention at the state level; and an examination of the rationale for a monopoly status for local distribution companies.

Although I do not necessarily agree with all of the analysis and conclusions reached by the study, I do believe it will be very useful as we assess the current and projected future of the natural gas industry. For these reasons, I ask that the study be published as a Committee Print.

Sincerely,

Philip R. Sharp

Philip R. Sharp
Chairman

PRS:nw

LETTER OF SUBMITTAL

Congressional Research Service
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Washington, D.C. 20540

April 16, 1982

Honorable Philip R. Sharp
Chairman, Subcommittee on
  Fossil and Synthetic Fuels
House of Representatives
Committee on Energy and
  Commerce
Washington, D.C. 20515

Dear Mr. Chairman:

As a consequence of your request of June 30, 1981, we undertook a major study of the underlying basis of natural gas regulation, and the regulatory options that Congress may want to consider. The result, entitled "The Eye of the Storm: A Study of Natural Gas Regulation," is enclosed.

The study is divided into two major sections: Book I deals with Federal regulation, while Book II covers State regulation. The latter was prepared for CRS by the staff of the National Regulatory Research Institute at the Ohio State University. Book II deals with the scope of State authority, major issues and problems of State regulators, monopoly characteristics and behavior of gas distribution, the impact of Federal regulation on State regulation.

Book I was prepared by the CRS staff. It consists of background chapters on the natural gas industry and Federal regulatory system, as well as wellhead regulation, written by Karen K. Nelson, Office of Senior Specialists; legal issues raised by wellhead price deregulation by Robert D. Poling, American Law Division; a discussion of the impact of technology on regulation by Langdon T. Crane, Science Policy Research Division; and an analysis of pipeline regulation by Alvin Kaufman, Office of Senior Specialists. Book I ends with a discussion of legislative considerations.

The project was coordinated by Alvin Kaufman, Senior Specialist in Mineral and Regulatory Economics.

We hope that the report will serve the needs of your subcommittee as well as those of the full committee and other Members of Congress.

Sincerely yours,

Gilbert Gude

Gilbert Gude
Director

Enclosure

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CONTENTS

SUMMARY 1

INTRODUCTION 14

BOOK I

FEDERAL REGULATION OF NATURAL GAS

I. OVERVIEW OF THE NATURAL GAS INDUSTRY 17

- A. Industry Organization and Structure 17
- B. Size 19
- C. Finances 20
- D. Trends 24

II. THE FEDERAL REGULATORY SYSTEM 26

- A. Regulatory Theory 26
- B. Theories in Retrospect 28
- C. Theories into Practice 30
    - 1. Wellhead 31
    - 2. Pipelines 31
    - 3. Distribution 34
- D. The Alaska Gas Pipeline and Regulation 35

III. FEDERAL WELLHEAD REGULATION 39

- A. Evolution of Natural Gas Wellhead Regulation 39
- B. The Natural Gas Policy Act 42
    - 1. Overview of the Act 42
    - 2. Developments Since Passage of NGPA 44
- C. How Has the NGPA Worked? The Pros and Cons of Revisions 48

IV. LEGAL ISSUES RAISED BY FEDERAL DECONTROL OF WELLHEAD PRICE REGULATION OF NATURAL GAS 55

- A. An Overview 55
- B. History and Background of Federal Regulation 56
- C. Current State Regulation 67
    - 1. Distribution 67
    - 2. Pipelines 69
    - 3. Production 70

D. Issues Raised by Wellhead Decontrol 73

1. Production Regulation 74
2. Pipeline Regulation 77
3. Distribution Regulation 92

E. Some Observations 94

V. TECHNOLOGY, NATURAL MONOPOLY AND REGULATION 96

A. An Overview of Technology 96
B. Technology and Natural Monopoly 105
C. Technology and Institutions 111
D. Technology and Regulation 117

VI. FEDERAL REGULATION OF NATURAL GAS PIPELINES 120

A. The Industry 120
B. Current Situation 126
C. Pipelines and Natural Monopoly 132

1. Investment 132
2. Costs 134
3. A Natural Monopoly 137

D. Pipeline Regulation 138

1. Contract Provisions and Regulation 139
2. The Impact of Contract Provisions 143

VII. LEGISLATIVE CONSIDERATIONS 150

A. Options for the Future 150

1. Contract Issues 151
2. Regulatory Options 152
3. Low Load Factor Customers 152
4. The Obligation to Serve 153
5. Transportation Prices 153

B. Regulatory Concepts 154

1. To Regulate or Not to Regulate 155
2. Utility Regulation 156
3. Common Carrier 158

C. Some Observations 159

APPENDIX IA: People Contacted 164

APPENDIX IB: A Review of Regulatory Theory 166

APPENDIX IC: A Review of Natural Gas Technology 172

APPENDIX ID: Gas Supply and Market Areas 190

BOOK II

STATE REGULATION OF DISTRIBUTION

THE SCOPE OF STATE AUTHORITY 196

MAJOR ISSUES AND PROBLEMS OF STATE REGULATORS 202

MONOPOLY CHARACTERISTICS AND BEHAVIOR 219

Legal Barriers to Intraproduct Competition 221
Monopoly, Technology, and High Investments Costs 225
Economies of Scale and Natural Monopoly 230
Rights of Way: A Case of a Scarce Community Resource 242
Price Discrimination 243
Vertical and Horizontal Integration 247
Interproduct Competition 248
Conclusions on Monopoly in Natural Gas Distribution 251

IMPACT OF FEDERAL REGULATION ON STATE REGULATION 253

The Effect of Federal Regulation of Wellhead Prices 253
The Effect of Federal Regulation of Pipeline Rates 255
The Effect of Federal Regulation on Distribution Rates 257
The Effects of Other Federal Regulation on State Regulation 258

APPENDIX: Detailed Scope of State Authority 265

SUMMARY

The possibility of deregulating natural gas production has given rise to discussions as to the affect this action will have on the cost of gas to the ultimate consumer on one end, and the advantages that decontrol would create for the producer (and the ensuing benefits to the industry and the public) on the other end. But what of the gas pipeline companies and distributors? Gas wellhead deregulation will invariably produce some disruptions in these two sectors, perhaps forcing them into unfavorable market positions which could not be cured without altering the regulatory schemes under which they operate along with the elimination of wellhead price regulation.

Changes in the supply and demand patterns for energy have been dramatic in the last decade, with gas consumption having begun a steady decline at the start of the 1970s. Given the changes in energy patterns and the inevitability of wellhead decontrol of natural gas under present law this study suggests and analyzes possible regulatory schemes that would be appropriate for the natural gas pipeline after wellhead deregulation. In order to come to some conclusions it will be necessary to review the elements of the industry, both economically and technologically. The various theories of regulation and how they apply to the gas industry will be discussed along with a brief review of the regulations that presently dictate pricing activities at the wellhead and the possible results of decontrol. Next, the legal implications of pipeline regulation are noted, followed by an analysis of the regulation of natural gas pipelines in terms of technological and economic factors. Having found that some of the major dilemmas brought on by wellhead decontrol would include contractual problems, the role of state regulation of production, and the proper form of Federal regulation of pipelines, the study concludes with a presentation of some regulatory options for the pipelines in light of these issues. These

options include deregulation, maintenance of the status quo, a common carrier system, or a combination of these concepts.

Structure and Performance

The effects of wellhead decontrol must be examined in light of the natural gas industry's three tier system - wellhead, pipeline, and distributor. The industry exhibits little integration horizontally or vertically. There does exist, however, an increasing number of affiliations among the three sectors. A number of utilities own or control their own gas supplies, and the pipelines tend to be heavily involved in gas production. The technology of the natural gas system causes the pipeline to be basically "tied" at both ends because of the limitations of transporting gas. There are definite suppliers who produce the gas under long term contractual arrangements at one end of the line. The gas is sold to specified distributors at the other end. Today we are seeing an increase in the diversification of activities by both pipelines and distributors so that the standard activity distinctions between producers, pipeline firms, and distributors are being blurred. Thus, there is a trend toward vertical integration.

The importance of the natural gas industry is reflected in the production and consumption figures (17.3 quadrillion Btu delivered to consumers in 1980) and the fuels position as one of the major sources of energy for both residential and commercial users. Gas is currently the largest source of domestically produced energy. Financially, gas utility companies fared better than the electric utility industry in terms of return on assets, but fell relatively far behind oil and other manufacturing industries.

Efforts to increase needed production of natural gas are underway. There are varying forecasts of the demand for natural gas in the next 20 years. Electricity and coal are believed to be major competitive threats although gas is expected to fare somewhat better than oil in terms of demand. The forecasts of natural gas suppy and demand, however, are controversial because of uncertainty regarding future resource availability as well as future costs.

Regulatory Concepts and Practices

Government regulation has been a major factor in the operation of the gas industry because of the long standing assumption that the industry is a natural monopoly. As such it is considered to be most efficiently run under regulatory surveillance rather than competitively. The major characteristic of a natural monopoly is its tendency toward decreasing costs as more output is concentrated in a single supplier, a condition especially prevalert in the utilities industry because of the large fixed costs and immobility of capital. In such an instance, regulation is introduced by government to restrict competition under the assumption that the customer can be served at least cost by a single supplier.

There appear to be opportunities for competition in some areas of gas transmission, such as providing for bidding on a new facility when the current pipeline reaches capacity. This could preclude the possible economies of scale found by increasing the diameter and the pressure of the pipe or through the construction of parallel lines running through the same compressor station to increase capacity (looping). The competition offered by the need for a new facility may be more important, however, than any economies of scale yielded by the existing monopoly. It may encourage suppliers of natural gas to become more aggressive in proposing new rates and services, thereby increasing the effectiveness of regulation by the commission. There is by no means a clear consensus on the degree of competition that is desirable in the utility industry. The different interests and objectives that have been promoted by the regulatory commission in their governance over natural monopolies have prompted questions and debates.

The current regulatory practice in the natural gas industry subjects producers and transmission companies to Federal regulation through the Federal Energy Regulatory Commission (FERC) and distributors to state authority. The Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978 dictate the activities of the Federal regulators over natural gas. Since the passage of the NGPA most "new" and high cost gas is now exempt from FERC jurisdiction. NGPA allows for some categories of gas to eventually become deregulated under varying time schedules. This issue, however, has stimulated much controversy and the future of the stipulations in NGPA are in question. Because the wellhead price was historically viewed as the essential activity for effective regulation of natural gas flowing in interstate commerce, the regulation of wellhead prices has in recent years become the centerpiece of Federal regulation. The modification of price regulation at the wellhead will inevitably have an effect on production. Changes in production regulation may change the operation of the pipelines, and may also have a regulatory impact on the distribution companies.

The potential for more significant state initiatives relating to natural gas production may be possible if Federal wellhead controls are abandoned without a clear delineation of the regulatory limitations to which the states will be subject thereafter. States may have the authority to impose their own wellhead pricing regulation in the absence of Federal legislative language prohibiting any such controls at the state level. State activity may also extend to taxation under decontrol. Gas producing states might have greater latitude to impose larger severance taxes on natural gas production in the absence of the current potentially conflicting Federal price ceilings under NGPA.

At the interstate pipeline stage, the Federal Government, under wellhead decontrol, would lose control of the price paid by the interstate pipelines for natural gas which they produced and shipped, or which they purchased from others and shipped. Examination of pipeline regulation at the Federal level should be made, since the new regulatory framework might also require modification of pipeline regulation.

Currently, interstate pipelines are federally regulated, while intrastate lines are subject to state regulation, except for that gas which is sold or transported in interstate commerce. The regulatory approach stipulated by the NGA established natural gas pipeline companies as natural monopolies in their service areas. The inflexibility of the natural gas transportation system, both physically and through assigned markets, has several institutional implications. One of the most important, and one which affects the price of gas, is the strong incentive for pipeline companies to negotiate long-term contracts with producers because of the high initial cost of extending pipelines to new markets and fields. These long-term agreements ensure the financial future of the pipeline and its ability to expand as necessary. Problems do arise, however, as expectations for the future can be grossly in error. Miscalculation can lead to distortions in future natural gas prices. Such past miscalculations in long-term contracts are evident today in the unusual market situation we now face from prices negotiated years ago. The uncertainty engendered by this long-term bias results in protective efforts in contract writing, such as take-or-pay, favored nation, and indexing clauses. As a consequence, the producer is insulated from market signals. Further, because of rolled-in pricing the consumer does not feel the impact of specific price negotiations until some time after the fact. Therefore, reasonable and effective negotiation for gas purchases are difficult to achieve under the current system. Proper market signals are not received at the time of negotiation and the entire market at the wellhead seems to lack the classical responsiveness of the free market system.

It appears that the inflexibility of gas pipeline transportation technology and service area allocation have mandated economic arrangments that provide supply security at the expense of proper and timely economic responses to supply and demand fluctuations. Similar inflexibilities can be observed in the relationship between pipelines and gas distributors. Regulators intervene in this segment of the industry because there is basically no competition among distributors. This, again, delays communication between the consumer and distributor, except where the consumer is able to switch to some alternate source of energy or make significant conservation efforts. In this sense, the industrial customer has an advantage over the residential consumer.

Pipelines have been moving from the pure utility mode to a modified form of common carrier status through arrangements to carry large quantities of gas for others for a fee. Companies are also shifting their efforts from expansion of the system toward developing additional supplies to serve existing customers. At issue is whether the changes in the pipeline's situation, after wellhead price deregulation, warrants moving away from transportation regulation. This, in large measure, hinges on whether the pipeline meets the characteristics of a natural monopoly. These include economies of scale (declining costs), unique technology, and high entry investment. In terms of a lack of flexibility and mobility, the gas pipeline does appear to meet the technologic criteria that limits the number of potential operators. Pipelines also meet the high entry investment, criteria. The lines are not labor intensive and do require a substantial entry investment. Excluding gas acquisition costs, and considering only those costs connected with the transportation of gas, economies of scale appear to be available for pipelines. Thus, it can be concluded that the pipelines meet the criteria for a natural monopoly and are appropriate candidates for some form of regulation.

State Regulation of Distribution

A major question arising in regard to distribution under gas decontrol is whether more strict scrutiny of purchase transactions on the part of state regulators is necessary and desirable in order to fill the potential vacuum of Federal wellhead decontrol, and thus assure customers of access to necessary quantities at fair prices. Currently, state regulatory authority spans a wide range of areas, including regulation of retail rates and to some extent wholesale rates, curtailments, addition of new customers and loads, and gas adjustment clause increases. The major problems currently facing state commissions are primarily ratemaking issues.

Several characteristics of the distribution sector must be considered in examining alternatives for regulating distributors. Because of the indivisibility of investment costs, capital intensive operations, and specialized, immobile resources, natural gas utilities are vulnerable to destructive competition. The potential for competition is dampened by the possibilities of price discrimination inherent in the physical connection and in laws preventing unauthorized hookups. The increased incidence of vertical integration backward into gas production by distributors could threaten the arms-length bargaining relationship that has often previously facilitated state regulation of distribution. The current Federal regulation over wellhead prices make distributors essentially helpless in controlling a major portion of their costs and thus, the prices to end users. Because the rates charged by interstate pipelines are federally regulated, state utility regulatory commissions must flow these charges through to ultimate users. While the NGA served to preempt certain limited state regulation, following the termination of wellhead control, broad powers to regulate both production and marketing of natural gas may again devolve upon the states.

Legislative Considerations

The price of natural gas will become the major issue as more expensive new gas gradually replaces old gas, resulting in a rise in gas prices. Some maintain this will occur more quickly under accelerated deregulation. This increase may be even more substantial because high cost gas is being contracted for by pipelines at higher than average prices. The situation is further complicated by the provisions of existing contracts. Over the years the contracts between the various sectors of the industry have acquired a number of accretions designed to protect the financial viability of both the producer and the pipeline. Chief among these are the purchased gas adjustment clause, take or pay clauses, minimum bill requirements, and price escalator clauses. These contract provisions tend to distort the market signals received by the producer and, as a consequence, make it difficult for the pipeline to adjust operations to the changes in the final market. In turn, the pipelines are protected by the purchased gas adjustment clause and the minimum-bill provision. This contracting system thus protects the financial viability of the producer and pipeline, but leaves the distributor exposed to the market.

Wellhead decontrol raises fundamental questions about the structure, operation and regulation of the industry. Various items have been identified as potential issues upon whose resolution the success of Federal wellhead decontrol may depend. These issues can be defined as: 1) Resolution of the producer-pipeline contract dilemma; 2) The legal effect of vacating wellhead regulation on possible expansion of state regulation of production and distribution; and 3) The proper form and content of any continued Federal regulation of interstate pipelines. The issue of contracts is considered by many to be the most serious obstacle to wellhead deregulation. As such, proposals to modify the NGPA decontrol timetable, coupled with downward renegotiation between producers and pipelines of decontrolled gas prices in return for upward renegotiation of old gas prices in 1985 have been suggested as solutions.

It is possible that the entire regulatory regime could be changed. In the event that the relationship between the various segments of the gas industry were changed, questions arise as to how low load factor customers would be treated, what would happen to the obligation to serve, and will transportation prices be higher then under the current system?

Comparing the Regulatory Alternatives

With the goal of seeking out a regulatory system that will no longer unduly insulate the producer from the price signals originating at the user's burner tip, as well as one that will respond effectively to the pressures of anticipated price increases under wellhead price decontrol, we can consider four basic options: remaining with conventional public utility regulation essentially the same as now in place, operating natural gas transmission systems without regulation; adopting a common carrier status for the lines; or devising a hybrid regulatory system possessing characteristics of both utility and common carrier regulation. In this latter case, we shall assume a system that provides a natural monopoly public utility status for an initial pipeline serving a market area, but subsequent expansion of service would be open to competitive systems. The rate-making process used would establish rates for transmission service rather than the purchase and sale of gas by the pipeline.

In considering these four alternatives, the basic goals of regulation can be used as the frame of reference. Chief among these are: the provision of adequate and reliable service by the regulated, achievement of economic efficiency, equity between all of the involved parties, assurance of the financial stability of the utility, and adequate response to market and price signals external to, but affecting, the regulated system. It is recognized that making such comparisons involves value judgments inherent in the goals as well as the intertwining of these factors. Nonetheless, such a comparison needs to be made, and the following table summarizes in a general fashion how these options match up with the specified goals.

Our study suggests that some form of pipeline regulation is a more likely choice than an unregulated transmission system. Whatever the regulatory system, however, it must generate sufficient and stable revenues for the utility, provide for adequate competition, and provide an easy transition from the present system. Economies of scale should also be permitted as there is some opportunity to take advantage of them in the pipeline system.

Utility regulation does not appear to provide stable or sufficient revenue and is not adequately reflective of market conditions because of the present contractual situation. This could be corrected to an extent by limiting the term of contracts to say three to five years, and requiring competitive bidding for renewals at least on the supply side; requiring the lines to make available a minimum percentage of capacity for carriage of gas for others; granting franchises to serve a market that are exclusive only up to the full capacity of the line, with subsequent service open through a competitive bid process. These changes would permit evolution of the system as conditions dictate, permit revenue stability over the long-term, but not necessarily in the short-term, encourage competition at both ends of the pipeline while exploiting economies of scale insofar as possible.

Common carrier regulation, on the other hand, would perhaps increase the effectiveness of competition and economic efficiency. It also poses a number of problems regarding access to capacity, tariffs levied on gas owned by the pipeline owners, handling of emergency situations, and competitive disadvantages for small distributors. The first two problems could be corrected by forbidding pipelines to carry gas owned or controlled by anyone having a financial interest in the line. The emergency coordination aspects can be handled by giving FERC emergency powers under those conditions perceived to be an emergency. Because producers and pipelines may be reluctant to deal with small distributors because of the small gas volumes involved these distributors would lack market power. This problem could be overcome by the formation of regional distributor associations to buy and store gas, or by a small distributor contracting with a larger neighbor to handle the chores for them.

Any of the regulatory concepts can meet all criteria if appropriate modifications are made to each. The modifications could make the system move closer to a common carrier. The goal of eventual common carrier status for the gas pipeline may be an appropriate future evolutionary target. An example of this evolutionary process might phase out the current system over perhaps a ten year period. This would involve certain stipulations during the transition period: renewing supply contracts through competitive bidding and for limited periods; limiting all existing contracts to a maximum ten years; steadily increasing the pipelines' percentage of capacity and operating new capacity only on a common carrier basis; instituting gas transportation contracts guaranteeing quantity and price set by negotiation or through regulation; banning pipelines from transporting any gas owned by that company; allowing distributors to form associations to negotiate gas purchases and transportation; installing FERC as adjudicator and mediator of disputes. Under this example, at the end of an appropriate transition period, the pipelines would be operating as modified common carriers with FERC acting as mediator. This system can be viewed as offering a possible route toward accomodating wellhead deregulation with a minimum of disruption.

BOOK I

FEDERAL REGULATION OF NATURAL GAS

By

Congressional Research Service

Alvin Kaufman
Langdon T. Crane
Karen K. Nelson
Robert D. Poling

18

INTRODUCTION

There is a strong possibility that controls on wellhead prices will be removed or be more rapidly deregulated sometime in the 1980s with attendant impacts on the industry. By and large the pipelines and distributors are in the eye of this storm. While the winds of deregulation swirl around the producer, other sectors of the natural gas industry remain relatively untouched. Yet once complete or accelerated wellhead deregulation becomes a fact, the pipelines and distributors may be drawn into the storm. Should this occur, it would be on top of the series of calamities that have shaken the natural gas industry in the past decade. It has suffered through several swings of the supply cycle, and now finds itself with relatively static demand and the possible loss of industrial markets. Through all of this, legislation has effectively supplanted regulation at the wellhead, and to an extent in the market place.

A measure of the changes that have occurred in the gas industry is available through comparison with total energy consumption. The latter increased at a 1.7 percent annual rate between 1970-79, while gas decreased at a 1.1 percent annual rate. This was a reversal of past trends. In the 1960-70 period, gas consumption rose at a 5.8 percent annual rate, compared with 4.3 percent for total energy. As a consequence, gas increased its contribution to total energy throughout the 1950s and 1960s. In 1971, gas accounted for approximately one-third of total energy consumption; by 1981, it only accounted for one-fifth. The decline is due to the fact gas production peaked at 22.2 Quadrillion Btu (Q) in 1973; by 1979, production had declined to 19.2 Q.

Given these changes, it appears to be an appropriate time to review the underlying basis of natural gas regulation and the regulatory options that may be of interest. To this end, Chairman Philip R. Sharp, on behalf of the Subcommittee on Fossil and Synthetic Fuels of the Committee on Energy and Commerce, requested CRS to undertake a study of the subject.

In the course of this study, discussions were held with a large number of people interested in the subject. These were selected to represent a cross-section of veiws. The study team found their opinions and value judgments to be invaluable in its deliberations. A list of those consulted will be found in Appendix IA.

The study is divided into two major books: 1. Federal regulation and 2. state regulation.

Book I, while dealing with wellhead regulation to a limited extent, concentrates on transmission. Under current law, wellhead prices will be deregulated to an extent by 1985. Therefore, the major questions for this sector are: when will deregulation occur, and what will be deregulated? Assuming the certainty of wellhead deregulation, there are questions as to the regulatory status of transmission and distribution. In the latter case there is a question of the impact on state regulation. In the case of the pipelines, there are questions as to whether these might not be deregulated as well, and if not what kind of regulatory regime might best fit the new circumstances.

The transmission section of the study will attempt to determine if a natural monopoly exists, and thus if regulation is warranted. From this, the study will move into an analysis of the available options including deregulation. These will be discussed in terms of their contribution to regulatory goals such as adequate and reliable service, economic efficiency, equity, financial stability, etc. In addition, an effort will be made to analyze the options in terms of the best regulatory regime, if any, for pipelines.

Distribution is covered in Book II - a separate, but integral, piece prepared by the National Regulatory Research Institute. That paper examines the scope of present state regulatory authority, the major gas issues percieved by state regulators, the monopoly characteristics of gas distribution, and the impact of Federal regulation on state regulation.

CHAPTER I

OVERVIEW OF THE NATURAL GAS INDUSTRY*

Industry Organization and Structure

The structure of the natural gas industry can be described as a three tier system -- wellhead, transmission, and distribution. Gas is produced at the wellhead, transmitted through a pipeline, and distributed to the ultimate consumer. The gas is reached by drilling, a costly and risky operation. The quantity of gas, if any, that will be produced from a particular drill site is uncertain, and the financial returns are in the future. The typical time between exploration and production is three to five years.1/ The wellhead price of gas in interstate commerce is generally regulated by the Federal Energy Regulatory Commission (FERC) and by the provisions of the Natural Gas Policy Act (NGPA) and the Natural Gas Act (NGA).

The second tier in the gas industry structure is the transmission stage, consisting of pipeline companies. The pipeline companies gather gas from many wells and transport it in large diameter pipelines to distributors and consumers. Aside from providing transportation services, the pipeline companies act as a wholesaler purchasing gas from the producer and selling it to the distributor or customer. In addition, some processing is required to take out liquids and unwanted contaminants, but compared to crude oil refining, natural gas is virtually a finished product when it comes out of the ground.2/ Independent

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* Prepared by Karen K. Nelson, Research Assistant - Mineral and Regulatory Economics.

1/ Natural Gas Issues. Arlington, Virginia, American Gas Association, May 1981. p. 3.

2/ Ibid., p. 3.

AN ABSTRACT OF PIPELINE REGULATORY CONCEPTS

Goal	CONCEPT				
	Common Carrier		Unregulated	Utility	Hybrid (Combination of Utility and Common Carrier)
	Pure	Oil-Type			
Adequate and Reliable Service	Assures reliability and service because still under regulation in regard to rates and service.	Not under adequate service obligations.	Possible poor service. Pipelines may shun markets with heavy residential load because they are low load factor customers.	Under obligation to provide service so must purchase adequate supplies and provide proper amounts at correct times. Assures adequate reserves.	Has obligation to serve, so assures adequate reserves. To assure reliability, however, FERC would have to be given emergency allocative powers.
Economic Efficiency	Increased competition should provide for increased efficiency.	Potential for competition would decrease if pipeline carries mostly its own gas.	In theory, should allow market to establish prices and investment patterns. But may encourage destructive competition because pipeline displays characteristics of natural monopoly.	In theory, regulation simulates competition; under decontrol may work against efficiency because it produces monopoly controls of the market and supplies.	Can be adjusted to assure efficiency by limitation on contract terms, required bidding for renewals, opening up additions to capacity to bidding.
Equity	Greater equity with market open to producers and supplies open to distributors. But small distributors may have difficulty in obtaining adequate supplies.	Because pipeline could own gas it transports, question of equal access to carriage by other suppliers.	Exacerbation of contract situation. Wellhead prices will rise without regulatory oversight to assure equity for "old" gas.	In theory, yes, but unequitable distribution can result because of gas ownership, i.e. gas will go only where owner has a line.	Requires lines to make available a minimum capacity for carriage of ga for others. Small distributors are assured access by creation of regional distributor associations o by contracting with larger neighbor
Financial Stability	Easier to assure because now only concerned with transportation costs and price. But must rely only on one commodity for revenues.	Same as pure common carrier.	New entrants would go bankrupt as a result of reducing prices to gain a foothold; old firms would have to compete to retain markets in areas where existing contracts are about to expire.	Generally assured. But, may be in a squeeze between wellhead and distributor, resulting in a drop in rate of return.	Revenue stability assured in the long-term, but not necessarily in t short-term.
Transmittal of External Market Signals	Existence of competition at all points should send proper market signals to each segment.	Rates paid for transportation by owners may constitute a rebate or subsidy to the owner-producer.	Consumer should receive "correct" price signal with resultant optimal allocation of resources to pipelines.	If various contract provisions remain in effect, such as take-or-pay, producer may be insulated from market signals for awhile.	Same as utility.

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pipeline companies carry gas from the southwest to the Midwest and Northeast. Pipeline companies generally own the natural gas they carry, but an increasing proportion of the gas being transported is for others. Interstate gas pipelines are under the control of FERC in regard to certificates of necessity, rates, and service regulation.

In the final industry tier, the distributor buys the gas from the pipeline company, odorizes it for safety, and sells it to industrial users, commercial buildings, and residential customers. In some cases the gas is stored in underground reservoirs during low demand periods in order to help meet peak season requirements. Gas is usually put into storage between April and September, and drawn down between October and March. Underground storage provides an efficient means of balancing fairly steady supplies with widely fluctuating seasonal demand while keeping pipeline capacity utilization at an optimal level. Underground storage may be owned by either transmission companies or distributors, depending on the contractual agreement between the two sectors. A take-or-pay contract on the part of the distributor will result in his possibly taking more gas than he may be able to sell at a given time, requiring him to own storage facilities. Two-thirds of the gas distribution companies are investor-owned, the rest publicly owned.3/ The latter, however, only handle a small part of the volume of gas. Distributors are regulated by state public service commissions, but are also affected by several Federal gas sale regulations.

There is some vertical integration among the three industry tiers. That is, most of the pipelines own or control substantial portions of their supply.

3/ U.S. Library of Congress. Congressional Research Service. The Structure of the U.S. Natural Gas Industry: A Brief Overview. By Howard Useem, February 28, 1977. Washington, 1977. p. 3.

Columbia Gas System is the only completely vertically integrated company since it is a major producer, transmission company, and distribution system.4/ However, there does exist an increasing number of affiliations among the three sectors of the industry. Major pipeline companies are increasingly interrelated with corporations that engage in exploration and drilling for natural gas in order to supplement their supplies.

Concentration of production among gas producer and pipeline companies has generally been decreasing since 1975, with the top 20 companies now producing about 50 percent of domestic production, having lost about eight percent of the production and five percent of the reserves between 1975 and 1979. The 20 largest holdings of reserves represent about 59 percent of the Nation's total. A similar situation exists in the transmission sector, the top 20 companies handling approximately half of the market.5/

Size

In 1975 there were approximately 3,750 firms selling interstate gas to 113 interstate pipeline companies which deliver gas to some 1600 local distribution companies.6/ Natural gas has grown to be a major source of energy for both residential and commercial users, and is currently the largest source of domestically produced energy. It supplies more energy for non-transportation applications than any other fuel. Gas is the primary energy source for more than half of all residential and commercial establishments, fueling 55 million

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4/ Major Companies of the Natural Gas Industry. American Gas Association, Gas Energy Review, v. 9, May 1981. p. 11.

5/ Ibid., p. 11.

6/ Useem, The Structure of the U.S. Natural Gas Industry, p. 2.

households and 160 million customers. Forty percent of the energy consumed in the industrial and agricultural sectors is gas. This fuel constitutes twenty percent of all energy consumed in the United States, and 33 percent of all domestically produced energy.7/

Total gas reserves at year end 1980 were 200 trillion cubic feet.8/ Total gas produced and purchased in that year was 17.3 quadrillion Btu, 15.4 of which were sold to ultimate consumers. Gross production of natural gas for 1979 in the U.S. totaled 21,883,353 mcf, 83 percent of which was produced in Texas, Louisiana, Oklahoma, and New Mexico. The U.S. exported 48,731 mcf of gas in 1980, most of it LNG from Alaska to Japan. Imports to the U.S. in 1980 amounted to 984,767 mcf, 81 percent of which came from Canada.

Finances

In 1980, the average wellhead price of gas was $1.48/MMBtu; the resale price (between pipeline and distributor) was $2.41/MMBtu; and the price to the ultimate consumer was $3.13/MMBtu. The end use price was up 24 percent from the previous year. The total sales of natural gas for the year was distributed among the various customer groups as follows:

	(trillions of Btu)	Percent of Total
Total	15,409.4 Btu	100.0%
Residential	4,823.0	31.3
Commercial	2,441.5	15.8
Industrial	7,862.0	51.1
Other	282.9	1.8

7/ Natural Gas Issues, p. 4.

8/ All statistics from Gas Facts (1980), unless otherwise noted.

Total revenue resulting from these sales totaled $48.3 billion, an increase of 24 percent over the previous year. Revenues from the industrial sector showed the most significant gain (30.2 percent). Total operating revenues of investor-owned gas utilities was up 28.2 percent to $86 billion in 1980. Net income was $4.3 billion, a 4 percent increase. Table 1 shows specifically in what area of the gas utilities the gains were made. Data in the table should not be added, since there is an overlap between classifications. Balance sheet figures for the gas utilities industry are shown in Table 2, indicating the general health of firms and levels of investment.

It may be useful to compare the gas utilities' financial position with that of other industries such as electricity and oil. Earnings of gas utilities have been relatively strong in recent years when compared with electric utilities, whose earnings have remained fairly stable, but below allowable returns since 1975. The ratio of profits to total assets is considered an appropriate comparison measure of financial performance. The gas utilities industry as a whole had a 5.8 percent rate of return on assets in 1980. The distribution sector of the industry had a return of 4 percent and transmission companies had a 6.6 percent return. In 1980 the average top twenty oil companies had an average ratio of 9.6 percent, and the electric utilities industry had a 3.8 percent return on assets.9/ For further comparison, all manufacturing companies averaged a 7.0 percent rate of return on assets, while the top Fortune 500 companies averaged 6.9 percent.10/ Gas is therefore faring better than the

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9/ U.S. Library of Congress. Congressional Research Service. Oil Industry Profits. Mini Brief No. MB 80215, by Bernard Gelb and Sylvia Morrison, May 28, 1980 (updated). Washington, 1980. p. 10.

10/ Ibid., p. 10.

TABLE 1

Operating Revenue and Net Income for Gas Utilities Companies, 1980 v. 1979

	1980 Operating Revenue (billions $)	Percent Change from 1979	Net Income (millions $)	Percent Change from 1979
Distribution Companies	$ 14.0	+ 18.8%	$ 452	- 12.7%
Transmission Companies	41.6	+ 39.0	2,514	+ 7.0
Integrated Companies	17.2	+ 19.2	837	+ 3.7
Combination Companies	13.0	+ 20.6	574	+ 7.7

Source: Gas Facts (1980 Data), American Gas Association.

TABLE 2

Balance Sheet - Total Gas Utility Industry, 1980

	Billions of Dollars	Percent Change from 1979
Total Plant	$66.8	+ 6.5%
Net Plant	40.7	+ 6.3
Current Assets	17.2	+ 11.6
Deferred Debts	2.2	- 9.4
Current Liabilities	18.1	+ 13.0
Total Long-term Debt	22.0	+ 4.8
Common Equity	25.6	+ 7.8

Source: Gas Facts (1980 Data). American Gas Association.

electric industry, but falls relatively far behind oil and other manufacturing industries in terms of return on assets.

Trends

Domestic reserves and production of natural gas has been declining since 1973, and may decline more rapidly in the future unless new sources are found and developed. Efforts in this direction are underway. Activity in gas exploration and drilling appear to be expanding, with the 1979 drilling rig count up, and seismic crew activity at the highest level in 20 years. In addition, some drilling has shifted to new areas that have the potential for significant, long-term gas production. However, there are no guarantees. According to the American Gas Association, with the present trends in exploration, U.S. supply levels are not expected to fall in this century, and may have the potential to increase.11/

Department of Energy forecasts, on the other hand, see the supply of energy shifting in the next 20 years from oil and gas to coal and to electricity generated from coal and nuclear power.12/ Electricity prices will be higher than for gas, but DOE believes the higher efficiency of electrical equipment will make electricity highly competitive for such uses as home heating. Electricity's share in new housing is thus projected to expand significantly in the future. Industry is also expected to increase its demand for electricity. DOE's forecasts show oil losing market share in all sectors, while gas remains relatively stable and coal and electricity make the major gains.

11/ Natural Gas Issues, p. 10.

12/ U.S. Department of Energy, p. 13.

The A.G.A. expects total U.S. energy demand to drop in the short-term future because of a sluggish economy, conservation efforts, and higher prices. Natural gas consumption is expected to fare somewhat better than oil. After a slight decrease in annual gas use in industrial and power plants, gas has since recaptured just under half of that drop. Conversions of residential units from oil to gas since 1978 are currently offsetting more than 50,000 barrels per day of oil. Total gas consumption per customer has been increasing, reversing a downward trend that began in 1972 and apparently ended in 1978.13/

The A.G.A. has projected some trends in the supply and demand of gas vis-a-vis other fuels to the year 2000.14/ Total U.S. demand for gas is expected to increase steadily for the next two decades. A.G.A. predicts that there will be sufficient gas available to the year 2000 to continue supplying at least 25 percent of the country's energy needs, possibly as much as 33 percent, but this conclusion is highly controversial.

13/ Ibid., p. 10.

14/ A.G.A. Gas Supply Committee. The Gas Energy Supply Outlook: 1980-2000. Arlington, Virginia, American Gas Association, October 1980.

CHAPTER II

THE FEDERAL REGULATORY SYSTEM*

Regulatory Theory

Over the years the Federal Government has intervened heavily in the operation of the gas industry. Therefore, it is important to discuss the concepts and the various theories involved in regulatory decisions. For our purposes, an overview of the concepts of natural monopoly as they relate to regulation will be appropriate.1/

The extremes of the market spectrum are viewed as pure monopoly on one end and pure competition on the opposite end. Pure competition can be defined as a market with an infinite number of sellers, complete independence of action, perfect standardization of products, no governmental intervention, and no monopoly power. Under a monopoly situation, there is a single seller with a differentiated product. The lack of competitors and the absence of a possibility of competitive entry is the prime limitation. If the Government decides that an industry is unable to function efficiently under competition, it reinforces the natural monopoly by establishing institutional barriers to entry that cannot be hurdled. This is the root of the concept of natural monopoly. That is, the Government steps in to regulate an industry as a natural monopoly because it is unable to function efficiently under competition.

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* Prepared by Karen K. Nelson, Research Assistant - Mineral and Regulatory Economics.

1/ For a more complete discussion see: Kahn, Alfred E. The Economics of Regulation: Principles and Institutions, Volume II. Santa Barbara, John Wiley and Sons, Inc., 1971.

The justification for regulation can encompass a number of items such as forcing the private economy to account for external costs, promoting development of an industry, assuring service, and the existence of what is deemed to be a natural monopoly. In the case of natural gas, the latter is of the greater importance.

Natural monopoly industries have characteristics such as decreasing costs over the long term, high threshold investment, and technologic conditions that limit the number of potential entrants. In such a case, regulation is implemented on the assumption that the customer can be served at least cost by a single supplier or a limited number of firms.

Once instituted, there are several theories of how regulation accomplishes its task. These include the public interest, capture, coalition-building, and equity-stability theories.

The public interest theory holds that by setting the utility revenue requirement at the cost of service (including a rate of return) and requiring that service be provided to all who desire it, the consumer will be protected from abuses of monopoly power. The capture theory takes issue with this concept by arguing that the regulated industry will come to dominate regulatory decision making.

The third theory, coalition-building, maintains that regulatory policy can only be successful by obtaining the support of special interest groups. This is achieved by setting rates below costs for groups whose support is sought, and above cost for others. Thus, cross-subsidies between groups, and income redistribution, are vital components of these theories. In this case, perceived social equity takes precedence over economic efficiency.

The equity-stability theory also concentrates on equity, but views its achievement, not in terms of coalition building, but because legislators are motivated to protect society from the negative effects of market forces. The theory of regulation is discussed in somewhat more detail in Appendix IB.

There is some controversy over the applicability of the various theories to regulation. This will be discussed below.

Theories in Retrospect

Trebing's suggestion for reform would involve a return to the public interest theory as the rationale for regulation, and to concentration on efficiency issues with the belief that many equity issues are, in reality, efficiency problems in disguise.2/ Thus, equity would not be treated as a separate issues, but nevertheless implicitly considered. He believes this can be done if commissions explicitly state the perceived benefits and costs of each regulation before taking action, and if they monitor the impacts of inflation on utility prices so that the effects on different classes of income can be noted. Market structure reforms, whereby competitive submarkets are created, will be just as important to improvements in efficiency as pricing and rate structure reform. This can be accomplished through eased entry, and a system of penalties and incentives as a substitute for cost-plus regulation.

Kahn raises questions concerning integration of public utilities on a wide geographical basis and discusses the growing issue of competition's role, specificially in the gas transmission industry.3/ Pipelines can compete for new demand in existing markets and for the patronage of existing customers when contracts come up for renewal. In terms of economies of scale, there are possi-

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2/ Trebing, Harry. Equity, Efficiency, and the Viability of Public Utility Regulation. In Sichel, Werner, and Thomas G. Gies, eds. Applications of Economic Principles in Public Utility Industries. Ann Arbor, University of Michigan, 1981.

3/ Kahn, The Economics of Regulation, pp. 152-71.

bilities for competition between lines and near their joints of junction as a result of the large criss-crossing network. The primary source of economies of scale can be found in a maximum diameter pipe and in increasing the pressure and constructing parallel lines running through the same compressor station to increase capacity. These economies taper off sharply once these limits of capacity are reached.

More important for economies of scale than just capacity, however, could be the centralized planning investment of a transmission system. It is questionable whether the economies of coordinated planning could be achieved under competition. Kahn suggests that the solution would be a "chosen instrument" approach for conducting the natural monopoly part of the operation while allowing independent action in other parts. Accordingly, the chosen instruments should behave like common carriers in order to preserve the opportunities for competition.

Transmission companies are not in a continuous competitive struggle among themselves. Competition will occur before the building of the pipeline when companies must compete for, enter into, and obtain commission permission in advance. After that, the particular market is withdrawn from competition. Competition then shifts to vying for new increments of demand that may emerge through expansion of both population and existing customer use. At some point, the additional demand may make a new pipeline feasible.

Competition in the pipeline industry comes into play when the pipelines begin to reach capacity. When a new facility must be built, the competitive advantage afforded by a new entrant might often be more meaningful, Kahn suggests, than any economies of scale which might be attained by permitting the established natural monopoly to construct a new facility. Even such limited competition is believed to encourage suppliers of natural gas to become more aggressive in proposing new rates and services, thereby increasing the effectiveness of regulation by the commission.

An alternative view is held by Harold Demsetz[4] who does not agree with the popular concept of natural monopoly. He argues that a monopoly makes expenditures that increase costs and simultaneously decrease profits. Demsetz does not feel there is a place for government regulation of public utilities at all. Competition, he feels, can produce more efficient results if left to function on its own. He suggests an auctioning process whereby firms are awarded franchises or licenses by the government, a tactic that has been criticized by some economists because it equates efficiency with a competitive rate of return, two different concepts. Trebing also finds fault with this system, stating that the bidding process actually includes political and economic influences, thus competition for the monopoly franchise may not be perfectly competitive.

The independent regualtory commissions have been the prominent way of dealing with natural monopolies in the United States. Because of the many different interests and objectives of such commissions, regulation has prompted many questions and debates.

Theory Into Practice

The natural gas industry is potentially subject to Federal regulation at the production and transmission stages, and to state regulation at the distribution stage. The Natural GAs Act (NGA), passed in 1938, is the major Federal law governing the industry. It applies to all gas except that "not committed or dedicated to interstate commerce" as of November 8, 1978, high cost gas, new gas, and gas from new onshore wells. Gas from these sources was exempted from FERC jurisdiction under the NGA by the passage of the Natural Gas Policy Act of 1978 (NGPA).

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[4] Demsetz, Harold. Why Regulate Utilities? In Shepherd, William G., and Thomas G. Gies, eds. Regulation in Further Perspective: The Little Engine That Might. Cambridge, Ballinger Publishing, 1974. pp. 125-35.

Wellhead. Wellhead regulation under the NGPA will be discussed more thoroughly in a later section. In brief, the NGA requires the producer to obtain a certificate of public convenience and necessity to start up, and permission to halt, operations from the Commission. Currently, regulations limit producers to certain specified prices for most gas. Wells deeper than 15,000 feet are not governed by any price ceiling.[5] In addition, producers are usually subject to some degree of state regulation also, in terms of utilization, well-spacing, directional drilling, and allowable production levels.[6] Under NGPA, some gas categories are ultimately subject to deregulation under varying time schedules.

Pipelines. Interstate gas pipelines are federally regulated, while intrastate lines are subject to state regulation, except for that gas which is sold or transported in interstate commerce. Interstate lines are governed by the NGA and the regulations issued by FERC to carry out the provisions of that Act. Permission to start up or to abandon service is required, and expansion or improvement of services may be ordered by the regulator. Rates are required to be "just and reasonable", and any rate changes must be approved by the Commission.[7]

5/ The Decontrol of Natural Gas Prices: A Price America Can't Afford. Washington, Energy Action Educational Foundation, February 19, 1981. p. 2.

6/ Pierce, Richard J. Natural Gas Regulation Handbook. New York, Executive Enterprises Publications, 1980. p. 33.

7/ U.S. Department of Energy. Energy Information Administration. Assistant Administrator for Applied Analysis. DOE/EIA-0201/11, August 1980. Washington, 1980. p. 14.

FERC has the power to apportion interstate pipeline costs among the various classes of pipeline customers. Throughout the 1950s, '60s, and into the '70s, FERC allocated costs in such a way that small load, small volume customers were paying higher rates than were large load, large volume customers. This was eventually passed on to the ultimate consumer, resulting in industrial customers paying a lower rate than residential customers. It was felt that residential customers, the low load users, were responsible for a share of the fixed costs greater than the total volumes of gas they received as determined by peak day demand, thus justifying their higher rates.8/

In 1973 a new allocative formula, the so-called "United" formula, was initiated which greatly reduced the disparity in rates paid by industrial and residential customers. Its rationale was related to the gas shortage which meant that gas supplies, rather than peak pipeline demand, dictated the constraints on deliveries. It was also hoped that assigning a higher proportion of fixed costs to the commodity component would increase rates for industrial consumers and consequently cause them to reduce their consumption. There has been much controversy over the years as to the validity of this price design method.9/

The allocation of a pipeline's variable costs among consumers is also controversial. Traditionally, they have been determined on a rolled-in, or cost averaging, basis. NGPA required a change in this method which may also affect the allocation of fixed costs. It was felt by the authors of the Act that rolled-in pricing had become inefficient because of the growing disparity "old" and "new" gas. At the same time, there was a desire to keep rates to residen-

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8/ Pierce, Natural Gas Regulation Handbook, p. 87.

9/ Ibid., p. 88.

tial customers as low as possible. These two facts resulted in a new method of cost allocation termed incremental pricing.

Under the incremental pricing rate design, residential customers would be allocated the less expensive "old" gas costs, while industrial customers would be paying for costlier new gas. Needless to say, industrial customers put up strong opposition so that a compromise between rolled-in pricing and incremental pricing was negotiated under NGPA.10/ The compromise involves separating customers into two groups, one of which is subject to a modified version of incremental pricing and required to pay a disproportionate share of the total costs of gas. This group consists primarily of large industrial users. Once the rate paid by these consumers equals the price of the appropriate alternate fuel in that region, however, FERC can no longer require any additional incremental pricing charges. The alternate fuel is determined by FERC. By increasing the amount of fixed costs allocated to purchasers subject to incremental pricing, the distributor may be able to minimize the overall cost of its gas purchases through a reduction in the charges from the pipelines incremental pricing account that the distributor must absorb before its incrementally priced customers reach the fuel oil ceiling price.11/ Thus, the distributors and the State agencies that regulate then have an incentive to reallocate fixed costs to consumers subject to incremental pricing up to the fuel oil price ceiling so that the distributor will then not be subject to additional incremental pricing charges.

Intrastate pipelines are affected in some ways by Federal regulation. They cannot normally sell gas to an interstate pipeline of local distributor

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10/ Ibid., p. 91.

11/ Ibid., p. 94.

without permission from FERC. Under shortage situations the gas may be sold on an unregulated basis for 60 days. Also, both producers and intrastate pipeline companies were concerned that gas sold by intrastate to interstate pipelines would be subject to Federal regulation under the NGA. To remedy this problem, NGPA permits sales of gas between intrastate and interstate pipelines without fear of facing NGA regulation if the gas is sold at "fair and equitable" rates, the sale is for no longer than two years, the sale can be interrupted in order to provide adequate service to the intrastate lines' customers, and the gas has not been purchased for resale.12/

Federal agencies directly regulate curtailment of interstate pipelines. Curtailment rules applicable to distributors that buy interstate gas, while under the control of state agencies may also be subject to the policies of Federal authorities. Before 1977, FPC had total control over curtailment policies, establishing priority customers on the basis of end use. Later developments put FERC in charge of implementing curtailment plans, DOE determined priorities, and the Department of Agriculture influenced policy where agricultural use was involved. NGPA subsequently revised the priorities whereby large universities and agricultural users gained new advantages. FERC's curtailment policy has since been questioned and remains one of the most controversial areas of pipeline regulation.13/

Distribution. Intrastate distributors, those that distribute gas produced only in the state in which it is sold, are subject to state regulation of rates, conditions of service, etc. Local distributors, those that receive gas from interstate pipelines are primarily State-regulated, but are also indirectly

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12/ Ibid., p. 80.

13/ Ibid., p. 101.

affected by FERC regulatory powers under NGPA. The most direct influence of Federal regulation on distributors is evident in rate design. Incremental pricing practices are imposed on the gas sold by interstate pipelines to certain industrial customers, and to distributors for resale to those customers. The distributor is required by NGPA to pass these incremental charges on to the consumer.14/

Indirectly, Federal regulation affects distributors in the curtailment area. In theory, distributors were allowed to practice curtailment policies differently from that of the pipelines. However, distributor curtailment practices have been very similar to those of the pipelines, believed largely as a result of Commission pressures and the fear of distributors that doing otherwise would prejudice any future pipeline curtailment proceeding. Federal regulations also indirectly affected the market growth patterns of distributors. Under FERC's rolling base period curtailment plan, States urged distributors to build up their residential loads in order to increase their percentage of high priority uses. Under the Commission's fixed based period plan, the distributors were ordered to move in the opposite direction because of a fear of not being able to meet demand in the future.15/

The Alaska Gas Pipeline and Regulation

The Alaskan Natural Gas Pipeline System has required some deviation from the normal regulation of pipelines as set forth in NGPA. Special sections of NGPA and ANGST were drafted specifically for the Alaskan system in the areas of rate of return on equity, project company tariffs, pipe design, and pricing treatment. The primary consideration was the question of how to compensate for

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14/ Ibid., pp. 109-10.

15/ Ibid., pp. 110-11.

the high risks perceived because of the size and cost of the system. The options available included the Federal Government bearing the cost of the risk by guaranteeing payments if the gas deliveries are less than predicted, shifting the risk to consumers by allowing the gas purchasing companies to pass costs through whether or not gas is delivered, or having the equity owners bear the risk.16/

A variable rate of return scheme was developed as an incentive to keep costs down. Under this system, the allowable rate of return on equity varies according to construction costs. As costs rise over the budget limit, the rate of return on equity is decreased. This system offers the sponsors lower compensation for a lack of efficiency. If pipeline construction costs are under budget the return on equity increases. Thus, there is an incentive to hold down construction costs.

Oversight on pipeline construction and design is maintained by the Office of the Federal Inspector. The total oversight activities for the Alaskan pipeline will far exceed those of any previous system.17/

The NGPA mandates that the delivered cost of the gas will be "rolled-in", with certain exceptions, because it is believed that private financing of the pipeline would not be available otherwise.18/ A special section of NGPA (109(a)(4)) specifies a ceiling price for gas from the Prudhoe Bay area and transported

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16/ Essley, Phillip L. A Federal Overview of the Alaskan Highway Gas Pipeline Project. In An Overview of the Alaska Highway Gas Pipeline: The World's Largest Project. New York, American Society of Civil Engineers, 1978. p. 122.

17/ Ibid., p. 123.

18/ U.S. Library of Congress. Congressional Research Service. Alaskan Natural Gas: When and How. Issue Brief No. IB 75083, by Gary Pagliano, Dec. 1, 1975 (updated Oct. 23, 1981). Washington, 1975. p. 5.

through the Alaska Natural Gas Pipeline. "Other costs" are incrementally priced with special incremental pricing provisions applicable.19/ The pricing section of NGPA applies irrespective of vintage or other production characteristics as would be applicable to other production.

Gas from Prudhoe Bay is useful to producers only if it can reach the lower 48 states. In order to make the gas transportable, given climatic conditions, the Alaskan pipeline system requires special quality standards. Therefore, gas produced at Prudhoe Bay must meet standards above those for gas produced elsewhere.20/ For example, the carbon dioxide content of the gas must be reduced to 1 percent by volume compared with 3 percent in the lower 48 states. This reduction is needed to prevent corrosion and improve transportation efficiency.

Most recently, special waivers were granted the Alaskan pipeline in order to encourage financing of the system. The three major exceptions granted were: 1. lifting the ban that forbids the three North Slope producers from holding an interest in the pipeline; 2. including in project costs the plant needed to condition the natural gas for pipeline transport; 3. requiring gas customers, with FERC approval, to pay the operating and interest costs on any of three completed pipeline segments after the date by which the entire system is to be completed, and even before gas begins to flow.21/ This last stipulation has been the most controversial, since it could potentially affect a tremendous number of consumers and runs contrary to current practices. Companies normally pass

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19/ U.S. Federal Energy Regulatory Commission. Order No. 45. Regulations and Statement of Policy. RM 79-19, August 24, 1979. Washington, 1979. p. 10.

20/ Ibid., p. 36.

21/ Senate Lifts Restrictions on Alaska Pipeline Work. Journal of Commerce, November 20, 1981. p. 23B.

along project costs only when the companies are providing a "used and useful" product. A utility or pipeline company desiring to recoup the cost of an abandoned project must apply to FERC. The latter then holds hearing to determine how much, if any, of the loss should be recovered from consumers.

CHAPTER III

FEDERAL WELLHEAD REGULATION*

Evolution of Natural Gas Wellhead Regulation

Before World War I natural gas did not make up a significant proportion of U.S. energy consumption. Not until pipeline technology began to develop and make transportation of gas to different parts of the country possible did the production of natural gas come to be a major industry. Production of natural gas followed an irregular market cycle which the states attempted to control through various forms of regulation. Congress, however, continued to press for a free market system.1/

Prior to the widespread use of natural gas, distributors were under some local government control, and then state control as they exceeded the boundaries of their municipalities. Once pipelines began to transport gas, the states wanted to regulate rates in some way because, like the distributors, the pipelines were believed to be natural monopolies. It was further felt the lines were charging excessive prices to local distribution companies and paying very low monopsonistic prices to producers.2/ The courts ruled, however, that the states could not control the rates charged by pipelines to distributors of interstate gas.

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* Prepared by Karen K. Nelson, Research Assistant - Mineral and Regulatory Economics.

1/ Merrill, Peter. The Regulation and Deregulation of Natural Gas in the U.S. (1938-1985). Discussion Paper Series no. E-80-13. Energy and Environmental Policy Center, Harvard University, January, 1981. pp. 6-7.

2/ Pierce, Natural Gas Regulation Handbook, p. 16.

Congressional attitudes towards regulation began to change in the 1920s as the ownership of pipelines and gas utilities became concentrated in a few holding companies. There was considerable vertical integration of the production and transmission sectors. In addition, consumers felt that pipelines were abusing their power and charging excessive and discriminatory prices. These factors combined to produce the Natural Gas Act passed in 1938, which stipulated that the pipelines would be federally regulated. The wellhead sector of the natural gas industry was not immediately subject to the jurisdiction of the Natural Gas Act.[3]

This system of partial regulation, however, proved to be ineffective. The FPC could not effectively regulate the rates charged by those pipelines that produced a large portion of their own gas supplies. These pipelines could continue to charge monopoly rates to distributors by charging themselves high prices for the gas they produced, inflating their total revenues. In addition, the producing states were able to impose variations of tariffs and export restrictions on field gas. As a result, they were able to increase revenues collected from consuming states and to reduce out-of-state movement of gas.[4]

The landmark case of Phillips Petroleum v. Wisconsin in 1954, wherein he Supreme Court interpreted NGA's powers as extending to the gas wellhead, was the beginning of Federal regulation of natural gas producers selling gas for resale in interstate commerce.[5] Initially, FPC tried to regulate each producer as an individual public utility, but this proved to be an overwhelming administrative burden. In 1960, an area rate approach to producer regulation was instigated, whereby rates were established for each producing area on the basis of average area production costs.

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[3] Merrill, Regulation and Deregulation of Natural Gas, pp. 8-9.

[4] Ibid., p. 9.

[5] Pierce, Natural Gas Regulation Handbook, pp. 20-2.

By the 1970s, natural gas shortages and reduced reserves were noticeable. This resulted from the combination of an increased demand for natural gas, the decreased number of new discoveries, and the fact that interstate gas pipelines were unable to compete with the unregulated gas of intrastate pipelines where gas commanded a significantly higher price than in the regulated interstate market. Thus, a large portion of new gas moved to the intrastate market. To illustrate the dramatic shift in supply pattern, two-thirds of new gas reserves in 1964-69 were dedicated to interstate markets, while over 90 percent of new reserves in 1970-77 were dedicated to the intrastate market.6/ To forestall this shift the price of new gas was allowed to rise and FPC developed emergency curtailment plans. In 1973 the FPC issued an order which set forth a procedure for determining pipeline curtailment priorities based on end-use categories. Nationwide producer rates were adopted in 1974 and revised every two years to reduce regulatory lag. These measures succeeded in attracting new reserves to the interstate market. The price of natural gas in the interstate market, however, did not go up high enough to equilibrate supply and demand. Curtailments exceeded 25 percent of requirements in 1976-77.7/ The issue of curtailments was a highly controversial policy area throughout the 1970s.

Because of the widespread belief by the public, as well as Congressmen, that the country was "running out of gas", deregulation was not a prevalent option to be considered. Deregulation was viewed as the road to higher prices

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6/ Merrill, Regulation and Deregulation of Natural Gas, pp. 17-19.

7/ Ibid., p. 28.

with little increase in supply. On the contrary, rationing, not a free market, would be in order. President Carter refused to consider any bills that were concerned with natural gas deregulation. At the time, however, gas exploration increased, spurred by higher intrastate prices, and several more states became producers. Thus, political support for deregulation began to increase.8/ The House of Representatives voted in favor of extending price controls nationwide, while the Senate voted to remove price controls completely. Thus, a compromise was needed to reconcile the two positions. The debate that followed resulted in the passage of the Natural Gas Policy Act of 1978.

The Natural Gas Policy Act

The NGPA is a compromise bill resulting from many years of controversy. It attempts to bridge the conflicting positions ranging between total producer regulation and no regulation. The purpose behind the bill was to eliminate the interstate/intrastate dichotomy in the regulation of producer sales, provide incentive for exploration, and minimize the potential for windfall profits.9/ This is accomplished by controlling producer prices, setting up a wellhead price deregulation time schedule for some segments of the industry, establishing an incremental pricing system, and initiating Federal regulation of the intrastate gas market.

Overview of the Act. The most talked of and controversial section of the Act is Title I in which the price of gas at the wellhead is controlled. There are a series of separate statutory ceilings applicable to some 24 different categories of gas. The categorization of gas is done by state agencies and sub-

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8/ Bethell, Tom. The Gas Price Fixers. Harper's June 1979. p. 44.

9/ Pierce, Natural Gas Regulation Handbook, p. 41.

ject to annual escalation. This is computed by varying price escalation formulas applied to the different gas classification.

Some of the gas categories are subject to total price deregulation at different times. On January 1, 1985, price ceilings are eliminated for new gas (from wells having begun drilling on or after February 19, 1977), for new onshore production well gas from a depth of more than 5000 feet and for gas sold under intrastate contracts in existence as of November 8, 1978. In 1987 new onshore production well gas from a depth of less than 5000 feet is deregulated. Either Congress or the President can reimpose the ceilings for a period of 18 months.10/

NGPA does specifically limit the operation of escalation clauses in intrastate contracts. That is, if the contract price is higher than the NGPA ceiling price at the time of enactment, escalation cannot exceed the NGPA annual inflation adjustment until the price equals the new gas price ceiling, after which escalation is permitted only up to the level of annual escalation authorized for new gas. A more complex area of contract regulation involves the case of an existing contract which contains a fixed price provision along with an indefinite escalation clause or deregulation clause. As long as the producer does not exceed the applicable ceiling set forth in NGPA, it can increase its price through reliance on the contractual provision. With the many different types of contracts in existence, however, and with the application of the stipulations of NGPA, this particular case becomes very unclear and complex. Several interpretations of the Act concerning this situation have been periodically thrown out by FERC. The latest ruling allows the parties to a contract

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10/ Ibid., p. 52.

to interpret an indefinite escalation clause as being "triggered by NGPA price ceilings if they originally intended the clause to have this effect.11/

Title II of NGPA contains the incremental pricing provisions which apply to gas sold in interstate commerce to industrial consumers. It was included primarily as a market-ordering mechanism and to protect the small commercial and residential consumer. First, an accounting mechanism was established under which the industrial surcharge and the offsets to small commercial and residential consumers were calculated by distributors. The surcharge on industry is used to reduce the cost of purchased gas by pipelines and as such, acts as a credit against the charge paid by customers exempt from incremental pricing. Thus, these consumers have a lower gas bill as a result of the industry surcharge.

Institutional authorization to act in emergencies by allocating gas among pipelines is granted in Title III of the NGPA. Title IV amends the previous curtailment policy to include agricultural users as high priority customers.

NGPA extended Federal producer price controls to the intrastate market for the first time in history. For gas produced and used in the state, the NGPA authorized states to establish lower ceiling prices than those established in NGPA.12/

Developments Since Passage of NGPA. The NGPA was conceived for the purposes of increasing activity in gas exploration and to control prices in a fashion that would permit a narrowing of the disparity between gas and oil prices. These were some of the short-term effects that it hoped to achieve, while in the longer-run it attempts to phase in a policy of deregulation. The arguments

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11/ Ibid., pp. 59-61.

12/ Ibid., p. 73.

on the effectiveness of the NGPA run to both extremes of accomplishing its goals on the one hand and promoting mass confusion in the industry on the other. It will be advantageous to first look at what has actually occurred in the gas industry in terms of supply and demand trends, investment levels, and pricing developments. We can then look at the varying reactions of each segment of the industry towards the events resulting from the passage of NGPA and their opinions on revisions needed.

The evidence on which to judge just how NGPA has affected supplies appears to be a mixed bag, and very much in the eyes of the beholder. New gas supplies have been increased during the seventies, but the real test of the NGPA will be whether the additions to supplies can continue to meet present demand as well as future projections. Drilling activity showed a slowdown in the early phases of NGPA when rig count decreased in early 1979. Activity started up again in May 1979, however, with the highest rig count in at least 20 years.13/ Pipelines and distributors have had access to new reserves of natural gas with additions in 1979 to proven reserves the highest since 1967.14/

Not everyone agrees, however, on the significance of these developments, or, for that matter, with the actual statistics. The American Gas Association claims that gas well completions and footage drilled are at all time highs. The Interstate Natural Gas Association points to the fact that additions to proved reserves are up over 1979, an increase over additions during the 1970s. C.M. Butler, Chairman of FERC, claims that reserve additions during the past few years have been essentially flat and that since the passage of NGPA, the percentage increase in new gas completions has been decreasing every year.

13/ Pierce, Natural Gas Regulation Handbook, p. 247.

14/ U.S. Library of Congress. Congressional Research Service. The Natural Gas Policy Act: Reform Revisited. Issue Brief No. IB 81020, by John Jimison, February 19, 1981 (updated August 31, 1981.) Washington, 1981. p. 7.

As a result, the gas reserves/production ratio has declined. He asserts that annual gas well competions have increased at a slower pace since the passage of NGPA than in five of the six preceding years.15/

Although the claims of increased drilling activity appear optimistic, most well classification filings for these wells were for section 103 on-shore development wells and section 108 stripper wells. Only 11.1 percent of well determinations were in the supposedly most promising categories. However, total estimated gas from these wells make up 58 percent of total gas expected from all types of wells.16/

Another twist in the outwardly optimistic supply trends involves the supply positions of the interstate pipelines. Although they have improved greatly, there is the question of the longevity of the improvement, since many of the new gas reserves are being depleted at a much faster rate than once was the practice. In addition, most of the increased drilling and reserve additions are related to existing fields rather than new areas where any major new oil and gas resource would lie.17/

On the demand side, one must look at the situation before the passage of NGPA when a substantial surplus had developed in the intrastate market, and interstate pipeline customers were not coming back on line even after the curtailments were lifted. Once the NGPA was signed, the gas industry proceeded to build up demand by encouraging use of surplus gas supplies that had developed, often referred to as the "gas bubble." Demand for natural gas, however, has

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15/ Senators Hear Conflicting NGPA Views. Oil and Gas Journal, Nov. 16, 1981. pp. 154-5.

16/ Pierce, Natural Gas Regulation Handbook, pp. 248-9.

17/ Jimison, The Natural Gas Policy Act, p. 7.

changed greatly, primarily as a result of higher levels of conservation effort among residential and commercial users. Conservation was such that total deliveries to these sectors have remained stable or declined slightly, even amidst a number of conversions from oil and new hook-ups.18/

The change in demand for natural gas was, of course, primarily a result of the pricing regulations implemented through NGPA. Natural gas demand was helped by the great surge in oil prices. The implementation of incremental pricing was designed to make industrial gas more expensive, but the world oil situation made substituting the available natural gas surplus for oil advantageous. A FERC order which allowed interstate pipelines to transport gas purchased by industrial and utility customers permitted the pipelines to operate closer to capacity than might otherwise have been the case.19/

The dichotomy between inter and intrastate pipelines remains a problem, although the volume and price differences between these lines are lessening under NGPA. Interstate pipelines have been paying higher wellhead prices in a given area and under a given Title I section of NGPA than intrastate lines, according to an Energy Information Administration (EIA) report. Some interstate pipelines paid 16¢/MMBTU more than that paid by intrastate lines. Under NGPA, pipelines have increased the intermarket transactions by more than a factor of ten, allowing the surplus of gas to be sold between markets.20/

The present controversy centers around measures to bring about decontrol earlier than the NGPA deadlines (1985 for most affected gas categories and

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18/ Ibid., pp. 9-10.

19/ Ibid., p. 9.

20/ Study Shows Interstate, Intrastate Gas Price Gap. Oil and Gas Journal, Nov. 2, 1981. p. 227.

1987 for some others) and make it apply to all gas instead of just new gas. The disagreement among the gas industry sectors as to which course of action to take has resulted in a delay in the stepped-up decontrol action favored by the present admininstration.

How Has the NGPA Worked? The Pros and Cons of Revision

The varying effects of NGPA regulations on the different sectors of the gas industry has resulted in a wide range of opinions as to the merits of the Act and whether or not there should be some immediate revisions in terms of altering the decontrol schedule as it presently stands in NGPA. Each segment of the natural gas industry has its own arguments for their particular position and within each sector further disagreement exists. From the producer, who rejects the rules of NGPA and presses for immediate deregulation, to the consumer, who fears sky-rocketing gas bills from decontrol, the discussion of NGPA and its future continues to fuel controversy on all sides.

Gas producers are by far the most vocal in their criticism of NGPA. The major group of producers supporting NGPA are those involved in exploration and drilling of expensive, decontrolled, deep gas.21/ Producers have felt restricted by the category criteria for gas, saying that the prices intended for certain wells have not been applied. In addition, they are calling for an end to incremental pricing.

Immediate or accelerated decontrol of natural gas has also been promoted heavily by FERC and DOE. The major benefits cited include an advance in drilling and exploration with a resultant decrease in foreign oil dependence, and a belief that this is the best way for gas prices to adjust to inevitable de-

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21/ Senators Hear Conflicting NGPA Views, p. 152.

control. The American Petroleum Institute argues that NGPA has resulted in an emphasis on deep gas drilling because prices for gas from below 15,000 feet are not controlled.22/ This, they say, shifts operators to deep gas when less expensive shallow gas could be developed, distorting prices. Representative Gramm (Texas) feels that NGPA has stifled exploration for new gas and does not provide the incentive to begin new drilling projects.23/ As a result, our foreign oil dependence has grown and the trend in exploration has been away from gas to crude petroleum because of the higher returns available for oil.

One estimate puts the decrease of imported oil under gas decontrol at an eventual 2.83 million barrels a day, with a reduction in price of a barrel of crude oil by $10 below what it would otherwise be without gas decontrol.24/ The same study estimates that gas supplies would also increase 5.89 trillion cubic feet or 25 percent over current levels. Another study by Glenn Loury25/ claims that immediate decontrol could result in an eventual reduction of 2-3 million barrels of imported oil each day and produce annual savings of up to $40 billion in funds now paid to foreign suppliers. Loury believes this could cause OPEC to lower prices or reduce the rate of price increases by reducing demand for imports.

22/ Decontrol of Natural Gas Prices Holds Spotlight During Annual API Meeting. Oil and Gas Journal, Nov. 16, 1981. p. 25.

23/ End Price Controls on Natural Gas? U.S. News and World Report, Nov. 30, 1981. p. 71.

24/ London, Paul A. How Fast Will Gas Prices Rise Under Decontrol? National Journal, August 8, 1981.

25/ Loury, Glenn C. An Analysis of the Efficiency on Inflationary Impact of the Decontrol of Natural Gas Prices. Natural Gas Supply Association, April 1981.

The other major argument for decontrol concerns gas prices. First, the higher gas prices under decontrol are expected to promote conservation. NGPA is accused of giving people an incentive to waste because the price is under its market value, which also discourages development of other fuels. Decontrol advocates believe that the increased prices will be less of a problem under immediate decontrol than under the present system and would not produce the drastic inflationary problems predicted by anti-decontrollers. It is argued that under NGPA, the price of gas will not reach half of its free market price by 1985, resulting in an almost doubling of prices upon decontrol. An initial price surge is expected under immediate decontrol, but prices should stabilize as gas users begin to conserve. Prices would rise to near residual fuel equivalent levels, so gas would compete with coal and fuel oil in the market.26/

The Independent Petroleum Association states that the current schedule in the NGPA produces a market distortion.27/ Because old interstate gas contracts are not scheduled for decontrol in 1985 and are moving up in price very slowly under NGPA, pipelines with large volumes of old gas have a huge cushion of cheap gas to subsidize the purchase of new gas. Thus, they have the ability to bid in the market for new gas supplies without their consumers feeling the full impact of that bidding. This gives those pipelines a great advantage over their competition who do not have such a cushion. Intrastate pipelines are at a disadvantage against interstate pipelines in this situation because of the growing disparity of supply between the two pipeline categories. Interstate pipelines have a much larger volume of low-priced gas under contract and are

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26/ U.S. Gas Price Decontrol Debate Centers on Cloudy Market Views. Oil and Gas Journal, July 13, 1981, p. 35.

27/ IPAA Calls for Gas Decontrol, WPT Wipeout. Oil and Gas Journal, Oct. 26, 1981. p. 60.

able to outbid the intrastate lines for high-priced gas since they can average their acquisition costs and still not price their gas out of the market.28/ FERC argues that the average gas prices might be less under rapid, complete decontrol than under partial because pipelines with big cushions of controlled gas no longer would be able to bid up prices of deregulated gas.

Another problem FERC sees for the pipelines is that the large volumes of gas that have been purchased under indefinite price escalator clauses could have the potential of carrying gas prices above the market clearing price. Pipelines might then have difficulty in reselling the gas for the price they had paid.

DOE expands the Reagan Admininstration's position by promoting decontrol as more efficient and as an incentive to conserve. They assert that consumers would be encouraged to convert to less costly energy, allowing gas to be allocated to those who value it most, resulting in a least cost mix of gas production. The agency admits that decontrol may lead to higher prices for consumers and a subsequent expanded producer revenue surplus. The present policy confers large benefits on those with access to controlled gas, while producers and distributors of competing fuels, consumers who are currently deprived of access to gas, and owners of gas resources are being disadvantaged. Total decontrol would result in temporary losses of real output but, DOE argues, adjustments would occur.29/

We can look to pipelines, distributors and consumer groups for the range of arguments against immediate and total decontrol of wellhead prices. In general, they argue that there has indeed been enough drilling so that NGPA has

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28/ Senators Hear Conflicting NGPA Views, p. 156.

29/ U.S. Gas Price Decontrol Debate, p. 36.

actually been a good incentive. They also argue that NGPA provides for sufficient increases in gas prices, claiming that since 1978 prices have risen 28 percent a year (average annual compound rate).30/ In addition, new gas price increases assure monthly wellhead price increases faster than the overall inflation rate. They predict that decontrol would not increase reserve levels significantly. The future price of gas under the various decontrol scenarios is a source of most of the controversy as there is considerable disagreement over the magnitude of price increases under total decontrol.

A.G.A., for one, does not believe that the big jump in gas prices in 1985 is inevitable. It believes that increases in gas prices and stagnant world crude prices have put NGPA price schedules back on the right path. Thus, NGPA price ceilings for new gas could be nearly at free market levels by January 1, 1985. A.G.A. admits that the price escalator clauses could cause a fly-up in prices in 1985 if Congress does not take some action on this problem issue.31/

Pipelines feel they would be under great pressure from both ends under total decontrol. Immediate decontrol, they say, would boost gas supplies and reduce demand, disrupting some end use markets. This would push pipelines deeply into a take-or-pay position with suppliers.32/ Take-or-pay is a contract condition in which the gas purchaser is required to pay for a minimum volume of gas. The Interstate Natural Gas Association states that the pipelines, in return for help in supporting acceleration of decontrol, will require protection

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30/ Quicker and More Thorough Deregulation of Gas Prices. Public Utilities Fortnightly, Oct. 22, 1981. p. 63.

31/ Senators Hear Conflicting NGPA Views, p. 156.

32/ U.S. Gas Price Decontrol Debate, p. 35.

against the triggering of escalation clauses which would raise some gas to 110 percent of the price of number 2 fuel oil.33/

Perhaps the largest group of anti-decontrollers, are those representing the consumer viewpoint. Any type of decontrol schedule will assuredly raise consumer gas bills significantly. Some experts predict that gas prices will try to catch up with oil in 1985, causing huge price increases which will squeeze residential gas consumers, fuel inflation, and force some industrial users to switch to oil. A study by the Energy Action Educational Foundation predicts that accelerated decontrol would add $370 billion to U.S. natural gas bills between 1981 and 1985.34/ The Citizen Labor Energy Coalition asserts that early decontrol would cause the U.S. a loss of 3.4 million jobs between 1982 and 1985 and shift $86 billion a year "from the pockets of American homeowners and tenants into the massive treasuries of the oil and gas companies".35/

A study by the Mellon Institute36/ asserts that deregulated gas would not rise to the price of oil. Gas, the study argues, is not in competition with oil, which has a virtual monopoly in the transportation sector, but with coal and electricity in the buildings and industry markets. If gas were to rise to the oil price level, the study shows that demand for gas would fall significantly, requiring virtually all the difference to be made up with coal and electricity. In addition, distributors would feel the profit squeeze first, while

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33/ INGA Mulls Stance on Gas Decontrol. Oil and Gas Journal, Oct. 12, 1981. p. 51.

34/ Gas Decontrol: Don't Forget Half of America. Christian Science Monitor, Sept. 25, 1981. p. 25.

35/ U.S. Gas Price Decontrol Debate, p. 37.

36/ Sant, Roger W., and Steven C. Carhart. Eight Great Energy Myths: The Least-Cost Energy Strategy - 1978-2000. Arlington, Virginia, Mellon Institute, 1981. pp. 39-40.

the producers receive the delayed effects. Consequently, the argument used by anti-deregulators that gas will reach oil price levels is weak if one accepts the implications of the study.

Especially hard hit may be the low-income group and those people on fixed incomes, according to A.G.A.[37] A.G.A. notes that a chain of events, beginning with a doubling of gas prices, would cause the low income family's gas bill to rise from 10.6 percent of its total income to 19 percent. In addition, the increase in gas costs to industrial and commercial customers would drive up the costs of goods and services which rely on natural gas in their production -- those that consume the bulk of the low income group's income.

If decontrol of gas is to occur, consumer groups tend to favor the schedule as it now stands in NGPA. Under NGPA's phased schedule, these groups believe consumers have time to make necessary adjustments in fuel use patterns and to institute conservation measures.

In any case, the essential questions regarding wellhead regulation are not whether to deregulate, but rather when and how much. It is apparent that the Congress has opted for deregulation, but wellhead gas could be deregulated now; by 1985 as required by current law; somewhere in between; or extended to a later date. Further, all gas can be deregulated or just certain categories of gas, such as "new gas" as defined by law. Inasmuch as the option has been essentially determined and just the details require decisions, wellhead options will not be further discussed in this paper.

37/ Energy Analysis. Arlington, Virginia, American Gas Association, April 9, 1981.

CHAPTER IV

LEGAL ISSUES RAISED BY FEDERAL DECONTROL OF WELLHEAD PRICE REGULATION OF NATURAL GAS*

An Overview

Proposals to decontrol wellhead prices of natural gas at the Federal level raise a variety of legal and regulatory issues of such significance that an examination of the impact of decontrol is necessary for all segments of the natural gas industry. The relationship of the production, transportation, and distribution components of the industry and the divided regulatory framework involving both Federal and state regulation provide a setting for the consideration of legal and regulatory issues which involve the most fundamental issues.

Where Federal decontrol of wellhead prices may take the industry may be significantly related to the history and background of the industry, for decontrol at the Federal level is in many respects a return to an earlier regulatory situation. Although significant changes have arisen in the Nation's use and production of natural gas since that earlier framework, many of the important changes which may be occasioned by Federal wellhead decontrol necessitate a thorough examination of the history of the industry and its regulation.

It is important at the outset to observe that "decontrol" is not a term of legal or regulatory art. Many things can be embraced within the generic usage of that term to describe legislation which would have as one of its purposes the removal, in whole or part, of Federal price ceilings for wellhead purchases of natural gas flowing ultimately in interstate commerce. Definitions of natural gas remaining subject to Federal controls, the nature of controls other than wellhead pricing, and a variety of other issues surround many of the proposals which might be considered as "decontrol" measures. Additionally, there is a developing, and somewhat incorrect, notion that Federal wellhead "decontrol" has already been ordained by the Natural Gas Policy Act of 1978, and that legislative approaches calling for wellhead decontrol merely accelerate, or provide greater, wellhead decontrol beyond the shifting administration of current law. Clearly, proposals for wellhead decontrol go well beyond the Natural Gas Policy Act of 1978 in many respects, and more importantly, raise a number of important policy and legal issues which were not thoroughly considered as a part of the extensive debate of the 1978 Act, largely because of its limited implications for further decontrol of wellhead prices.

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* Prepared by Robert D. Poling, Legislative Attorney.

The purpose of this section of the report is to explore the history and background of some of the legal and regulatory issues, to analyze issues likely to attend legislative consideration of wellhead decontrol, and perhaps, to identify issues which may be raised following wellhead decontrol.

We turn first to a brief discussion of the history and background of the regulation of natural gas.

History and Background of Federal Regulation

Federal issues relating to natural gas began to emerge with its significant production. Many states established state oil and gas conservation laws dating back as early as 1878, when the State of Pennsylvania enacted a statute relating to the plugging and casing of wells.[1] The discovery and development of new oil and gas fields in California, Oklahoma, and Texas in the 1920s which re-

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[1] See, Legal History of Conservation of Oil and Gas, A Symposium, published by the Section of Mineral Law of the American Bas Association (1938). p. 1.

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sulted in the production of oil and gas in excess of market demand, wasting these resources, renewed earlier state efforts at conservation.2/ Much of the early legal activity arose out of the need to develop legal rules establishing the rights of surface owners to oil and gas obtained from pools running under land owned by many. In addition to these rules of capture, other technical aspects of oil and natural gas production led to the need for legal rules establishing the means for efficient production and recovery.3/

The growth of the oil and natural gas industries during the early 1900s inevitably brought the subject matter into the legal framework of the Federal Government in connection with the power of Congress to regulate interstate commerce under the Commerce Clause of Article I, Section 8 of the United States Constitution.

It appears that the first case in which the U.S. Supreme Court considered state conservation regulation of oil and natural gas was Ohio Oil Company v. Indiana (No. 1),4/ in which an Indiana statute that prevented the escape of natural gas in the open air was upheld as constitutional. It was argued that the effect of the statute was a taking of property without adequate compensation in violation of the Fourteenth Amendment. In analyzing the rights of surface owners to the oil and gas beneath the surface, the Court concluded that the State had a valid interest in protecting the rights of several surface owners, where the action of one owner might divest another of gas or oil derived from a common natural reservoir. Thus, because the issues involved were matters of the regulation of real property, the State could validly carry on such regulation.

2/ Ibid., p. 1.

3/ See generally, Economic Aspects of Oil Conservation Regulation, by Wallace F. Lovejoy and Paul T. Homan (The Johns Hopkins Press, Baltimore 1967).

4/ 177 U.S. 190 (1900).

This principle was later reaffirmed by the Supreme Court in Lindsley v. Natural Carbonic Gas Company.5/ However, in the same year, the Court struck down an Oklahoma statute which sought to prevent the transportation of natural gas in interstate commerce in West v. Kansas Natural Gas Company.6/ There, the Court held that state prohibitions on transportation of natural gas in interstate commerce violated the Due Process Clause of the Fourteenth Amendment and constituted an unconstitutional interference with, and restraint upon, interstate commerce, even though Congress had not legislated on the matter.

The theory advanced by Justice McKenna in his opinion for the Court was that states did not have the authority to intrude upon matters of interstate commerce:

> If the states have such power, a singular situation might result. Pennsylvania might keep it coal, the Northwest its timber, the mining states their minerals. And why not the products of the field be brought within the principle? Thus enlarged, or without that enlargement, its influence on interstate commerce need not be pointed out. To what consequences does such power tend? If one state has it, all states have it; embargo may be retaliated by embargo, and commerce will be halted at state lines. And yet we have said that "in matters of foreign and interstate commerce there shall be no state lines."7/

In effect, the status of the law following these decisions would have permitted state regulation of wastage in oil and natural gas production, but would not have allowed a state to prevent transportation of oil or natural gas outside of the state.

5/ 220 U.S. 61 (1911).

6/ 221 U.S. 229 (1911).

7/ 221 U.S., at 255.

Consistent with applicable Supreme Court precedent governing the interstate transportation of oil,8/ the Supreme Court held that certain state taxation of natural gas in interstate commerce was void under the Commerce Clause.9/ Similarly, states could not establish a preferential obligation requiring priority usage of natural gas in the state of production, thereby withdrawing natural gas from interstate commerce.10/

Perhaps the most significant Commerce Clause case was *Missouri* v. *Kansas Natural Gas Co.*,11/ in which the Supreme Court decided in 1924 that states could not regulate the sale, transportation, or delivery of natural gas in interstate commerce without running afoul of the Commerce Clause, even in the absence of Federal regulation of such interstate sale, transportation, or delivery. Although the Supreme Court was willing to recognize the need for some state regulation for conservation purposes, it was unwilling to permit state regulation of natural gas flowing in interstate commerce. State efforts to set prices were immediately struck down as they applied to gas flowing in interstate commerce.12/

But, the Supreme Court upheld a California statute providing for natural gas conservation to maintain oil production on the theory that the correlative rights of surface owners with respect to a common source of supply of oil and gas were a valid matter for state regulation.13/

8/ *Eureka Pipe Line Co.* v. *Hallahan*, 257 U.S. 265 (1921).

9/ *United Fuel Gas Co.* v. *Hallahan*, 257 U.S. 277 (1921).

10/ *Pennsylvania* v. *West Virginia*, 262 U.S. 553 (1923).

11/ 265 U.S. 298 (1924).

12/ *State Corporation Commission of Kansas* v. *Wichita Gas Co.*, 290 U.S. 561 (1934).

13/ *Bandini Petroleum Co.* v. *Superior Court*, 284 U.S. 8 (1931)

In 1937, the Supreme Court struck down a Texas Railroad Commission regulation providing for prorationing of natural gas production, on the theory that the effect of the regulation required private producers to purchase gas from others in order to fulfill their contract obligations and that such action constituted a taking of private property in violation of the Fourteenth Amendment.[14]

While the early litigation involving natural gas raised basic questions concerning the constitutional scope and nature of state regulatory powers, the Natural Gas Act of 1938 marked the first Federal statutory entry into the regulation of natural gas.

As with electricity,[15] the legal inability of the states to regulate the interstate aspects of the natural gas industry led to Federal regulation. The Natural Gas Act of 1938 provided for the regulation of rates and charges for the interstate sale and transportation of natural gas. The Federal Power Commission (predecessor of the Federal Energy Regulatory Commission) was authorized to establish "just and reasonable" rates for gas transportation[16] based upon the fair value of the property used for transportation,[17] and to regulate the entry and abandonment of service in interstate markets,[18] among other things.

Following the enactment of the Natural Gas Act, a body of significant administrative and judicial decisions interpreting the Act became the basis of the Federal regulation of natural gas for over forty years.19/ One of the first judicial issues to reach the U.S. Supreme Court involved the relationship of the authority under the Act to state authority. As an indication of the general interpretation to follow, the Court held that companies subject to the Act could not be required by the states to extend facilities and provide service in an area already served by another natural gas company subject to the Act.20/

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[14] Thompson v. Consolidated Gas Utilities Corp., 300 U.S. 55 (1937).

[15] Public Utility Commission v. Attleboro Co., 273 U.S. 83 (1927).

[16] See, Section 4 and 5 of the Natural Gas Act, Public Law 75-688, 52 State 821 (1938).

[17] Ibid., Section 6.

[18] Ibid., Section 7.

But the first major constitutional decision under the Act came in 1942 as the result of a rate proceeding in Federal Power Commission v. Natural Gas Pipeline Co.,21/ in which the Court upheld the constitutionality of the Natural Gas Act as within the power under the Commerce Clause and found that the Act did not violate the Fifth Amendment due process provisions. The decision had the effect of sustaining the broad authority of the Commission's discretion to establish "just and reasonable" rates, so long as such rates were not confiscatory by upholding the Commission's finding that a six and one-half percent rate of return on fair value was adequate.

It was also quickly established under the Act that the states were unable to set the rates which the local utilities would pay for natural gas purchased from interstate companies subject to the Act,22/ and that the jurisdiction of the FPC was that which had been beyond the reach of the states

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19/ See generally, The Regulation of Natural Gas by Charles E. Crenshaw, 19 Law and Contemporary Problems 325 (1954).

20/ Illinois Natural Gas Co. v. Central Illinois Public Service Co., 314 U.S. 498 (1942).

21/ 315 U.S. 575 (1942).

22/ Public Utilities Commission of Ohio v. United Fuel Gas Co., 317 U.S. 456 (1943).

prior to the Act.23/ However, state jurisdiction with respect to retail sales was preserved, since the Act only applied to sales for resale in interstate commerce. Thus, state regulation could require certificates from interstate pipelines selling natural gas directly to industrial customers.24/

In Federal Power Commission v. Hope Natural Gas Co.,25/ the Supreme Court upheld the rate methodology adopted by the FPC in approving the use of the rate base, upon which the "just and reasonable" rates were calculated, as including a company's "actual legitimate cost" of interstate property, less depreciation and depletion, plus allowances for unoperated acreage, working capital, and future net capital additions.

The most significant judicial decision with respect to FPC jurisidiction came in 1954 in Phillips Petroleum Co. v. Wisconsin.26/ The decision held that independent producers of natural gas not actually shipping gas through their own pipelines, but who sold gas to interstate pipeline companies, were natural gas companies with the meaning of the Act, and therefore subject to rate regulation by the Commission. Thereafter, the Commission undertook the price regulation at the wellhead of natural gas subject to the Act.27/ The difficulties of

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23/ Panhandle Eastern Pipe Line Co. v. Public Service Commission of Indiana, 332 U.S. 507 (1947).

24/ Panhandle Eastern Pipe Line Co. v. Michigan Public Service Commission, 341 U.S. 329 (1951).

25/ 320 U.S. 591 (1944).

26/ 347 U.S. 672 (1954).

27/ Committee Print, "The Economics of the Natural Gas Controversy," Subcommittee on Energy of the Joint Economic Committee, U.S. Congress 95th Congress, 1st Session (1977). p. 6; see also, The Field Price Regulation of Natural Gas, by Clark A. Hawkins (Florida State University Press, Tallahassee) 1969; Natural Gas Regulation--An Evaluation of FPC Price Controls, by Robert B. Helms (American Enterprise Institute for Public Policy Research, Washington, D.C.) 1974; and, The Federal Commission, Course Handbook Series Number 133, (Practicing Law Institute, New York) 1954.

determining on a company basis the cost-of-service for each independent producer became an unworkable burden for the FPC and inevitably led to the area basis of establishing wellhead prices in 1963.28/ And by 1968, the FPC was finally upheld in its establishment of a two-tier price structure for area pricing of natural gas.29/

The evolution of various pricing methodologies for natural gas demonstrated the administrative flexibility and the breadth of discretion established for wellhead pricing under the Natural Gas Act.

By the early 1970s the problems of increasing importance for the Commission had become the shortages of delivered supplies of interstate gas and the need for the development of curtailment procedures to be used by companies with inadequate supplies to meet contractual needs.30/

Following a long series of administrative hearings and a series of incremental efforts to solve the problems, the FPC finally undertook to resolve the shortages of natural gas through the imposition of mandatory curtailment plans adopted for each individual pipeline. These curtailment plans typically imposed a system of priorities for various natural gas retail customers based upon the nature of the use which such customer made of the gas. Residential customers were generally given the highest priorities, followed by various commerical and public uses, with boiler fuel and interruptible customers in the lowest priority category.31/

28/ Wisconsin v. Federal Power Commission, 373 U.S. 294 (1963).

29/ Permian Basin Area Rate Cases, 390 U.S. 747 (1968).

30/ See, for example, Federal Power Commission v. Louisiana Power & Light Co., 406 U.S. 621 (1972).

31/ See, FPC Order 467-B End Use Curtailment Plan; see also, Consolidated Edison Company of New York, Inc. v. Federal Power Commission, 512 F.2d 1332 (D.C. Cir. 1975).

But even these curtailment measures were inadequate in providing for allocation of natural gas among pipelines, for they were only designed to allocate among a given pipeline's customers and were not intended to require similar curtailment for all pipelines on the same basis. At the same time actions were taken to provide incentives for producers to provide additional gas in interstate commerce. Various short-term sales of natural gas were approved in a manner that would not subject the gas to rate and other FPC jurisdiction, and the Commission approved certain direct sales of natural gas at unregulated prices and allowed interstate pipelines to transport "direct sale" gas in a fashion similar to that of a common carrier.[32]

By the end of the 1976-77 winter, the Congress perceived the need for additional authority to alleviate potentially disruptive national shortages of natural gas.[33] The Emergency Natural Gas Act of 1977 [34] provided supplemental authority in the form of direct delegation of emergency powers to the President. Among other things, the Act authorized the President to declare an emergency triggering various provisions permitting the acquisition of *intra*state natural gas, previously beyond Federal reach.[35] The effect of the Act was to provide authority to reach supplies of natural gas, including certain *intra*state gas subject to state price regulation, in order to meet emergency needs beyond the ability of a single interstate pipeline to provide through curtailment procedures. The Act, therefore, potentially constituted, by its express terms,36/ a significant preemption of state regulation of intrastate natural gas. Although the Act's authority expired on August 1, 1977 without the declaration of a single emergency, the Act evidenced a congressional willingness to substantially expand the scope of Federal jurisidiction over natural gas production and delivery, even if only in emergency circumstances.37/

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[32] See, FPC Order 533.

[33] See, Natural Gas Shortages, Hearings before the Subcommittee on Energy and Power of the House Committee on Interstate and Foreign Commerce 94th Cong., 1st Sess. (1975).

[34] Public Law 95-2, 91 Stat. 4 (February 2, 1977).

[35] Ibid., Section 6 (a).

After lengthy debate and much consideration, Congress enacted as one component of the so-called five part "National Energy Act", the Natural Gas Policy Act of 1978.38/ This Act constituted a major new Federal policy of statutory regulation of prices of natural gas at the wellhead. The Act provides for a somewhat complicated system of price regulation for natural gas based upon several statutorily specified and defined categories of natural gas, including such categories as new natural gas produced from the Outer Continental Shelf, new onshore gas, gas currently dedicated to interstate commerce, existing intrastate gas under contract, gas sold under rollover contracts, and various other categories.39/

The effect of this scheme of gas categorization is to establish a current ceiling price and to provide for periodic price increases in accordance with formulated ceiling prices subject to inflation adjustments, depending upon the category of the natural gas involved. The Act's object is to achieve the free market determination of prices for certain, but not all, categories of natural gas which will no longer be subject to price ceilings after January 1, 1985.

36/ Ibid., Section 14.

37/ Permanent enactment of provisions similar to the 1977 Act were incorporated into Title III of the Natural Gas Policy Act of 1978.

38/ Public Law 95-621, 92 Stat. 3350 (1978).

39/ Natural Gas Policy Act, *supra*, at Title I.

Because of the complex nature, and the administrative burden, of ascertaining the category for particular natural gas, Congress chose to authorize the delegation of the initial determination of gas category to producing state regulatory commissions, subject to possible review by the Federal Energy Regulatory Commission.40/ The state determination of gas category has the effect of automatically applying the established gas prices set by FERC in accordance with the price ceiling provisions.

The Natural Gas Policy Act of 1978 has taken center stage in the continuing debate over legislative proposals to provide for Federal decontrol of wellhead prices. Many of the proposals under consideration today would modify the Title I price ceiling provisions to eliminate ceiling prices for some or all categories of natural gas. Some proponents would have the decontrol occur prior to the 1985 date under NGPA for the lifting of certain category ceilings, and others would abolish totally wellhead price authority for all natural gas categories simultaneously at a certain future date.

In addition to the price ceiling provisions of Title I of the NGPA, the Act also provided for other pricing mechanisms, including incremental pricing for certain industrial users. Because the D.C. Circuit Court of Appeals has just recently invalidated the legislative veto of the incremental pricing regulations by the House of Representatives, some consideration of the incremental pricing matter may become an important agenda item for the Congress.41/

40/ Ibid., Sections 501(c) and 503.

41/ See, Consumer Energy Council of American v. Federal Energy Regulatory Commission, No. 80-2312, (D.C.Cir. decided January 29, 1982).

Current State Regulation

Distribution. State regulation of natural gas has focused on all three segments of the natural gas industry: production, transportation, and distribution. Obviously, state regulation of production and transportation of natural gas flowing in interstate commerce was preempted by Federal regulation under the Natural Gas Act of 1938 of those activities, but the relationship of the state and Federal regulation is extremely important in understanding the current regulatory scheme. We will first consider state regulation of retail distribution of natural gas.

The distribution and sale of natural gas was also a matter initially within state regulatory domain through the general regulatory powers of the state with respect to the franchising of corporations. State regulation of natural gas distribution companies arose out of the need to accommodate capital investment by providing special rights to geographic service areas. The granting of such corporate rights was offset by requiring of such companies obligations of service and by imposing rate regulation. In this respect, electric and natural gas retail distribution regulation have many similarities.

Both types of enterprises were generally regulated by the states through the granting of certificates of public convenience and necessity, which granted exclusive right to service areas and often required rate regulation in exchange for the right to do business.42/

Although as has been indicated, the regulation of wholesale rates for natural gas in interstate commerce was declared by the courts to intrude upon Federal prerogatives under the Commerce Clause and eventually wholesale rates

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42/ See generally, State Control of Business Through Certificates of Convenience and Necessity, by Ford P. Hall (Indiana University, Bloomington) 1947.

in interstate commerce were governed by Federal legislation, states undertook broad regulation of retail rates charged for natural gas, as well as wholesale rates charged for intrastate natural gas. Under early state rate regulation, the courts upheld state regulation of retail rates providing for "fair return upon the value" of the property employed in the enterprise.43/ Based upon early court approval of state rate regulation, and a long series of later judicial decisions bearing upon the method of calculation of rates,44/ states continue to exercise as a principal form of regulation, broad powers to establish the retail rates, charges, and nature of services provide by natural gas distribution utilities.45/

Because the sovereignty of each state provides it with the jurisdictional ability to establish and conduct regulation in the manner it deems most appropriate for itself, uniformities among states on specific aspects of utility regulation are often lacking, and it is frequently difficult to generalize about state regulation, except in the broadest terms.

In addition to the regulation of rates for retail natural gas sales, most state regulatory utility commissions are charged with the traditional obliga-

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43/ *Smythe* v. *Ames*, 169 U.S. 466 (1898); and, *Bluefield Water Works & Improvement Co.* v. *Public Service Commission of West Virginia*, 262 U.S. 679 (1923).

44/ Several cases prior to Federal regulation are instructive. See, *San Diego Land & Town Co.* v. *National City*, 174 U.S. 739 (1899); *San Diego Land & Town Co.* v. *Jasper*, 189 U.S. 439 (1903); *Wilcox* v. *Consolidated Gas Co.*, 212 U.S. 19 (1909); *Minnesota Rate Cases*, 230 U.S. 352 (1913); *Galveston Electric Co.* v. *Galveston*, 258 U.S. 388 (1922); *Georgia Railway* v. *Railroad Commission*, 262 U.S. 625 (1923); *McCardle* v. *Indianapolis Water Co.*, 272 U.S. 400 (1926); and, *St. Louis & O'Fallon Railway Co.* v. *United States*, 279 U.S. 461 (1929).

45/ Federal and State Commission Jurisdiction and Regulation--Electric Gas and Telephone Utilities, (Federal Power Commission), (1973). See also, Chapter V, infra.

tions associated with utility regulation to assure that natural gas distribution companies maintain adequate service to customers, and do not abandon of service with state approval.

For consuming states purchasing large amounts of natural gas in interstate commerce where the wellhead prices are subject to Federal control, much of the the state ratemaking process devotes itself to the determination of the costs of local distribution service and the addition thereto of the purchase price of the gas at the city-gate from pipelines to establish the ultimate price at the burner tip for the retail consumer. This retail rate result is accomplished in most states under fuel adjustment clauses, regulatory provisions which allow for the direct pass through of the full acquisition price of natural gas by the distribution companies.46/

Thus, under the current scheme of regulation, state commissions are engaged principally in licensing entry into natural gas distribution for an exclusive geographical area, regulation of the adequacy and quality of service, the establishment of the local distribution cost component of ultimate retail rates, and the regulation of wholesale rates for intrastate natural gas.

Pipelines. While Federal legislation provides for economic regulation of natural gas pipelines operating in interstate commerce, the states remain free to regulate natural gas pipelines operating wholly within a single state.

It generally appears that where intrastate pipeline economic regulation is carried on it is principally in the form of utility cost basis rate regulation, similar to that carried on under the Natural Gas Act at the Federal level.

46/ See, Committee Print, "Electric and Gas Utility Rate and Fuel Adjustment Clause Increases, 1975," Subcommittee on Intergovernmental Relations and the Subcommittee on Reports, Accounting, and Management of the Senate Committee on Government Affairs," 94th Cong., 2d Sess. (1976).

While there are differences from state to state, the relationship of intrastate natural gas lines to the local distribution system and to the interstate natural gas pipelines appears to have resulted in a system of regulation similar to that at the Federal level.47/

Production. The early efforts which states initiated to regulate the production and conservation of natural gas have already been briefly traced.

In addition to conservation and orderly production regulation, producing states quickly developed the need for new regulatory approaches to resolve the legal conflicts arising from the respective rights of adjacent landowners to oil and gas pools beneath the surface. Thus, the establishment of state regulatory mechanisms also provided for the regulation of the correlative rights of surface owners by establishing rules governing production and recovery techniques.48/ As has already been noted, the U.S. Supreme Court upheld state conservation laws relating to the production of natural gas as early as 1900.49/ In 1935, the U.S. Congress gave its approval to the Interstate Oil Compact,50/

47/ See generally, Origins of the Certificate of Public Convenience and Necessity: Developments in the States, 1870-1920, by William E. Jones, 79 Columbia Law Review 426 (1979).

48/ See genrally, Economic Aspects of Oil Conservation, by Wallace F. Lovejoy and Paul T. Homan (The Johns Hopkins Press, Baltimore) 1967; and Conservation of Oil & Gas--A Legal History, 1948 (Use and Abuse of America's Natural Resources), Edited by Blakely M.Murphy (Arno Press, New York) 1972.

49/ Ohio Oil Co. v. Indiana (No. 1), 177 U.S. 190 (1900).

50/ The original compact may be found at 49 Stat. 939 (1935). The most recent version of the approved compact was Public Law 94-771, 90 Stat. 2365 (1976). For background on the compact, see, Interstate Compact on Oil and Gas (12th Extension), Hearings before the Subcommittee on Communications and Power of the House Committee on Interstate and Foreign Commerce, 92d Cong., 2d Sess. (1972); and Consenting to Extension of Interstate Compact to Conserve Oil and Gas, Senate Report 94-771, 94th Cong., 2d Sess. (1976).

under which producing states voluntarily obligated themselves to undertake regulation to prevent the waste in production of natural gas.51/

Following the enactment of the Natural Gas Act in 1938, several important decisions further delineated the powers of states to regulate the production and conservation of natural gas.

The question of the type and nature of state conservation was presented to the Supreme Court in Railroad Commission of Texas v. Rowan & Nichols Oil Co.52/ In that case the issue raised was the validity under the Fourteenth Amendment of the Texas Railroad Commission order limiting and prorating production of an oil field at 2.32% of its hourly potential, with exception granted for certain marginal wells, which if their low capacity was curtailed would result in their premature abandonment. The Supreme Court, however, refused to intrude on the state administrative decision. "[W]hether a system of proration based upon hourly potential is as fair as one based upon estimated recoverable reserves or some other factor or combination of factors, is in itself a question for administrative and not judicial judgment."53/ In effect, the Court found that the regulation did not constitute a taking of property in violation of the Due Process Clause of the Fourteenth Amendment.54/

In 1950, the Supreme Court was presented with the question of whether Oklahoma could validly fix minimum prices on all natural gas taken from fields

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51/ See, for example, 1976 Legal Report of Oil and Gas Conservation Activities published by the Interstate Oil Compact Commission (Oklahoma City, Oklahoma) 1976.

52/ 310 U.S. 573 (1940).

53/ 310 U.S. 573, at 581.

54/ See also, Railroad Commission of Texas v. Rowan & Nichols Oil Co., 311 U.S. 570 (1941), and Railroad Commission of Texas v. Humble Oil & Refining Co., 311 U.S. 578 (1941).

located within the state. The Cities Service 55/ case arose after a state commission proceeding established minimum gas prices on the basis of evidence that low prices would make enforcement of conservation more difficult, would result in the abandonment of wells before all recoverable gas had been extracted, and would contribute to an uneconomic rate of depletion and economic waste of gas by promoting "inferior" uses. The Court sustained the state action over the objection that it was violative of the Fourteenth Amendment and constituted a burden in violation of the Commerce Clause. In relying on Thompson v. Consoldiated Gas, supra, the Court said:

> That a legitimate local interest is at stake in this case is clear. A state is justifiably concerned with preventing rapid and uneconomic dissipation of one of its chief natural resources. The contention urged by appellant that a group of private producers and royalty owners derive substantial gain from the regulations does not contradict the established connection between the orders and a statewide interest in conservation...
>
> We recognize that there is also a strong national interest in natural gas problems. But it is far from clear that on balance such interest is harmed by the state regulations under attack here. Presumably all consumers, domestic and industrial alike, want to obtain natural gas as cheaply as possible. On the other hand, groups connected with the production and transportation of competing fuels complain of the competition of cheap gas. Moreover, the wellhead price of gas is but a fraction of the price paid by domestic consumers at the burner-tip, so that the field price as herein set may have little or no effect on the domestic delivered price. Some industrial consumers, who get bargain rates on gas for "inferior" uses, may suffer. But strong arguments have been made that the national interest lies in preserving this limited resource for domestic and industrial uses for which natural gas has no completely satisfactory substitute.56/

Whether this rationale would survive today in light of the current relationship of wellhead prices to transportation costs is questionable.

55/ Cities Service Gas Co., v. Peerless Oil & Gas Co., 340 U.S. 179 (1950).

56/ Ibid., p. 187.

Curiously, the question whether a state order fixing minimum prices intruded upon the Natural Gas Act was not raised in this case, and the issue awaited the determination by the Court in Natural Gas Pipeline Co. v. Panoma Corporation,57/ before state minimum prices for interstate natural gas were struck down as an intrusion upon the exclusive authority of the FPC under the Natural Gas Act.58/

More recently, the Court in Northern Natural Gas stuck down state requirements that purchases of natural gas be made ratably from all wells in a particular field as being an intrusion upon the exclusive jurisdiciton of the Federal Power Commission under the Natural Gas Act.59/

Thus, it should be observed that the existence of the wellhead pricing provisions of the Natural Gas Act, and the scheme of Federal regulation generally imposed under the Act, have been significant impediments to more expansive production limitation and regulation by the states.

Issues Raised by Wellhead Decontrol

There are a number of important legal and regulatory issues raised by various current proposals for Federal decontrol of wellhead pricing of natural gas. Because the wellhead price, as we have seen, was historically viewed as the essential activity for effective regulation of natural gas flowing in interstate commerce, the regulation of wellhead prices has in recent years become the centerpiece of Federal regulation.

For this reason, the thorough consideration of legal and regulatory issues which may be raised in connection with decontrol necessitates a close examina-

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57/ 349 U.S. 44 (1955).

58/ See also, Phillips Petroleum Co. v. Oklahoma, 340 U.S. 190 (1950).

59/ Northern Natural Gas Co. v. State Corporation Commission of Kansas, 372 U.S. 84 (1963).

tion of each of the three segments of the natural gas industry and a review of the regulation at both the Federal and state levels of each of the three segments.

While it may seem basic, the modification of the regulation at the wellhead will inevitably have an effect on production. Changes in production regulation may change the operation of the pipelines; and further up the pipe to the distribution companies, wellhead changes may also have a regulatory impact.

We turn now to each of the three segments of the industry.

Production Regulation. Decontrol of Federal wellhead prices for natural gas raises important questions concerning the authority the states may have to impose their own wellhead pricing regulation in the absence of Federal legislative language prohibiting any such controls at the state or local level. This is so because the precise limits to which states may establish conservation and wellhead production regulation have not be fully litigated without the existence of the Natural Gas Act. In short, the Natural Gas Act intervened in the process of more extensive state production regulation in the late 1930s, so that the line of cases following the Natural Gas Act dealing with general prorationing and conservation statutes were found to intrude upon the regulation of interstate natural gas established under the Act.

The nagging question which arises in the context of proposed Federal wellhead decontrol is whether the states could, for example, impose minimum prices on all natural gas produced in a state in the absence of Federal wellhead controls. While the early Commerce Clause cases suggest that such a result may be deemed to interfere with interstate commerce, the abondonment of the significant form of Federal regulation may permit a result whereby producing states are able to determine either directly or indirectly the price of natural gas.

Under the Natural Gas Policy Act of 1978, the matter of state authority over production and wellhead pricing has not been addressed. A recent case relating to the decontrol of oil at the Federal level is instructive and perhaps analogous.

Such an issue was raised in *Mobil Oil Corp*. v. *Dubno*,60/ a case in which the U.S. District Court for the District of Connecticut struck down a provision contained in a recently enacted Connecticut tax law which imposed a gross receipts tax on companies engaged in refining and distributing petroleum production and further prevented the companies from raising their wholesale prices in Connnecticut. In effect the anti-passthrough provision of the Connecticut law precluded the possibility of raising retail prices beyond an average amount such price might be raised in other eastern seaboard areas.

The gross receipts tax itself--applied to earnings derived from activity within the State of Connecticut--was conceded by the companies in the suit to be valid.61/ However, the cost passthrough prohibition contained in Section 13(b) of the Connecticut Act62/ applied to prices of certain petroleum products subject to regulation under the Emergency Petroleum Allocation Act,63/ but for which the regulatory controls had been removed. It was the exempted status of these products from regulation under EPAA which became the focal point for the

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60/ 492 F. Supp. 1004 (D. Conn. 1980).

61/ The validity of such a tax would seem to be supported by *Washington Rev. Dept.* v. *Stevedoring Assn.*, 435 U.S. 734 (1978); *Complete Auto Transit Inc.* v. *Brady*, 430 U.S. 274 (1977); and, *Colonial Pipeline Co*. v. *Triangle*, 421 U.S. 100 (1975).

62/ Public Act 80-71 (1980).

63/ The Emergency Petroleum Allocation Act, 15 U.S.Code Section 751 *et seq*.

discussion in Dubno. After a review of the provisions and the legislative history of EPAA, the court found that:

> ...analysis of the EPAA, its legislative history and its administrative implementation reveals that "exemption"--far from relinquishing petroleum product pricing to state regulation--constitutes an affirmative federal decision that petroleum products should be free from all price regulation, and the EPAA objectives will best be served by an unregulated free market subject only to standby federal controls. Section 13(b) [of the Connecticut statute] is plainly in direct conflict with the federal regulatory scheme outlined above--i.e., it directly conflicts with the federal determination reached by the President and approved by Congress, that such products should be free of price regulation and their prices established by an "unimpeded free market." [Emphasis in original] 64/

It should be apparent that this interpretation of the preemptive nature of EPAA is a far-reaching opinion, because it specifically addressed the pricing component of EPAA regulations and because it found an intention to preempt even where Federal regulatory controls under EPAA had been removed.

A similar issue was addressed in another case involving a New York gross receipts tax which was challenged in Mobil Oil Corp. v. Tully.65/ There, the Court struck down provisions of a New York tax for essentially the same reasons as in Dubno. Both the Dubno and the Tully cases were appealed to the Second Circuit Court of Appeals, where that Court dismissed both actions66/ on the basis that the questions were within the exclusive jurisdiction of the Temporary Emergency Court of Appeals (TECA) which has jurisdiction over cases involving

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64/ Mobil Oil Corp. v. Dubno, supra, at 1013-1014.

65/ 499 F. Supp. 888 (N.D.N.Y. 1980).

66/ Tully, 639 F.2d 912 (2d Cir. 1981); and, Dubno, 639 F.2d 919 (2d Cir. 1981). For additional background on both Dubno and Tully, see Legal Times of Washington (October 6, 1980), at p. 13.

EPAA. The Tully case was appealed to TECA, which affirmed the lower court ruling.67/

These cases, although applied in a different regulatory context, suggest that decontrol of natural gas might not prevent state regulatory actions in the vacated zone of regulation unless Congress specifically preempts state action or manifests a very clear intent on the matter.

Apart from direct regulation of the production and gathering of natural gas, the potential involvement for state activity also extends to taxation. The recent Supreme Court decision upholding the Montana coal severance tax68/ suggests that natural gas producing states might have greater latitude to impose larger severance taxes on natural gas production in the absence of the current potentially conflicting Federal price ceilings under the Natural Gas Policy Act. The current existence of conflicting price ceilings operates to prevent significant severance taxes, but without that price regulation severance taxes may become a significant vehicle to raise the prices of natural gas at the burner tip.

Thus, the potential for more significant state initiatives relating to natural gas production would seem possible, and perhaps constitutional, if Federal wellhead controls are abandoned without a clear delineation of the regulatory limitations to which the states will be subject thereafter.

Pipeline Regulation. The Federal decontrol of natural gas prices at the wellhead raises a number of legal issues in connection with interstate pipeline regulation. First, as has already been discussed, the absence of Federal

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67/ 653 F.2d 497 (T.E.C.A. 1981).

68/ Commonwealth Edison Co. v. State of Montana, 49 U.S.L.W. 4957, ___ U.S. ___ (1981).

wellhead price regulation appears to return Federal regulation to a status similar to that prior to the Phillips Petroleum case, supra. However, it should be observed that even this frequent characterization of natural gas wellhead decontrol is somewhat inaccurate, since total decontrol would also remove the authority under the Natural Gas Act which existed, and was exercised, before Phillips to regulate the prices paid by non-independent producer-pipelines. Thus, decontrol would return Federal powers to a situation more closely analagous to that prior to the enactment of the Natural Gas Act in terms of wellhead pricing authority. In essence, total wellhead decontrol, alone, would permit the Federal Government to regulate the rates for interstate pipeline transportation on a cost of service basis, but would not permit the Federal regulation of the price paid by the interstate pipelines for natural gas which they produced and shipped, or which they purchased from others and shipped.

The issue raised by many in connection with wellhead decontrol is that an examination of pipeline regulation at the Federal level should be made, since the new regulatory framework might also require modification of pipeline regulation.

One concept that is sometimes mentioned is to abolish current pipeline regulation in favor of a form of common carrier regulation at the Federal level. Many of the issues which might be raised in connection with such a proposal are illustrative of general issues raised in connection with Federal pipeline decontrol, and therefore the common carrier concept is worthy of some extended analysis.

At common law, the concept of common carrier legal duties was understood to require that a transportation enterprise which held itself available to provide common carriage for compensation had a legally enforceable duty to carry for all who sought carriage services.69/ As statutory franchises were granted to permit certain public service carriage, frequently carriage for hire was required to be common carriage and obligations were imposed to carry commodities at regulated and nondiscriminatory rates.

Oil pipelines, unlike natural gas pipelines, have been historically regulated at the Federal level as "common carriers," and the experience there provides an important background for the consideration of possible common carrier status for interstate natural gas pipelines.

Almost as an afterthought of congressional interest in railroad regulatory reform, the major Federal enactment providing jurisdiction over interstate petroleum pipelines was incorporated into the legislation improving railroad regulation. The Hepburn Act70/ remains today the primary Federal statutory enactment over oil pipelines, and its legislative history is most instructive in understanding present oil pipeline regulation.

On May 4, 1906, as amendments to the railroad reform bill were being taken up on the Senate floor, President Theodore Roosevelt sent a message to the House and Senate transmitting a report by the Commissioner of the Bureau of Corporations of the Department of Commerce and Labor on the subject of transportation and freight rates in the oil industry. That message provided in part:

> ...that the Standard Oil Company has benefitted enormously up almost to the present moment by secret rates, many of these

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69/ See generally, Carriers, Sections 1 through 19, 13 American Jurisprudence 2d.

70/ 34 Stat. 584 (1906), 49 U.S. Code Section 1, et seq. (1976). It should be noted that the recent amendments to the ICC Act did not separately codify the provisions of the Hepburn Act which continued to apply to oil pipelines.

> secret rates being clearly unlawful. This benefit amounts to at least three-quarters of a million a year. This three-quarters of a million represents the profit that the Standard Oil Company obtains at the expense of the railroads; but of course the ultimate result is that it obtains a much larger profit at the expense of the public.71/

Shortly after the communication from President Roosevelt was read into the record, Senator Lodge of Massachusetts called for the consideration of this proposed amendment. As proposed on the floor in modified form, the so-called Lodge Amendment brought oil pipelines under the Interstate Commerce Act:

> Any Corporation or any person or persons engaged in the transportation of oil or other commodity, except natural gas or water for municipal purposes, by means of pipe lines or partly by pipe lines and partly by railroad, or partly by pipe lines and partly by water, who shall be considered and held to be common carriers within the meaning and purpose of this act... 72/

Senator Lodge offered this explanation of his proposed amendment:

> ...Oil is one of the greatest articles of interstate commerce carried in this country, and it is now absolutely outside and beyond any Governmental regulation whatsoever... the oil is brought to the trunk lines through small local feeding and gathering lines, as a rule. There are practically two great companies that control pipe lines engaged in interstate Commerce. One is Standard Oil, which is said, to control 90 per cent. I do not know whether that is correct or not.
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> The other is the Pure Oil. They do not own the wells, and they buy the oil of the well owner, and the charge for the transportation is taken out of the price, as appears in the copies of the certificates and receipts which I have.
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> Those well owners are absolutely at the mercy of the pipelines. I have has cases brought to me, which in this fifteen-minute debate I can not enlarge upon, where an independent refinery has been deprived of its supply of oil be-

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71/ 40 Cong. Rec. 6358, 59th Cong., 1st Sess. (1906).

72/ 40 Cong. Rec. 6361, 59th Cong., 1st Sess. (1906).

> cause it would not agree to the prices of the pipe lines. A small well owner is compelled to take the price that is offered by the controller of the trunk line...73/

Lodge's argument was premised upon two major points: first, that some form of regulatory review be created at the Federal level, and secondly, that a regulatory mechanism be created to assure that small independent oil producers be treated fairly in the establishment of oil pipeline rates. After a discussion of the commodities which should be covered by the amendment, with exception written in for natural and artificial gas, the Lodge Amendment was adopted by the Senate, by a vote of 74 yeas, 0 nays and 14 not voting.74/

Thereafter, a "commodities clause," prohibiting shipment of company-owned oil, was adopted in language that was sent to the Conference Committee by the Senate.75/

In the Conference Committee, however, the language of the commodities clause was changed, without explanation, from a prohibition applicable to all regulated common carriers (including pipelines) to a prohibition applicable only to railroads.76/

Thus, when final action was taken by both the House and the Senate, the commodities clause only prohibited railroads from shipping their own commodities. Had the commodities clause been made applicable to oil pipelines, it would have required the immediate divestiture of oil pipelines from producer and refinery interests. There is, however, every reason to believe from the

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73/ 40 Cong. Rec. 6365-6, 59th Cong., 1st Sess. (1906).

74/ 40 Cong. Rec. 6373, 59th Cong., 1st Sess. (1906).

75/ 40 Cong. Rec. 7017, 59th Cong., 1st Sess. (1906).

76/ House Conference Report No. 5003, 59th Cong., 1st Sess., (June 23, 1906) at 4.

legislative history, that Congress did not intend such a divestiture, for it thought that the legislated common carrier status would provide an adequate check on shipper-owned oil pipelines and their operations.

Within six months of the enactment of the Hepburn Act, the Roosevelt Administration initiated what was to turn out to be the first major interpretation of the Sherman Antitrust Act of 1890 77/ in the presentation of a suit against Stndard Oil of New Jersey, 33 corporations, and seven individual defendants, including John D. Rockefeller, on November 15, 1906. The suit charged violations of Section 2 of the Sherman Act and sought the breakup of the Standard Oil empire. The three judge panel in the Circuit Court ordered the divestiture of control of many subsidiaries of Standard Oil of New Jersey in its opinion of November 20, 1909.78/

Among other comments the court made this observation about the Sherman Act:

> The purpose of this statute was to keep the rates of tansportation and the prices of articles in interstate and international commerce open to free competition. Any contract or combination of two or more parties, whereby the control of such rates or prices is taken from separate competitors in the trade and vested in a person or an association of persons, necessarily restricts competition and restrains commerce. The formation or maintenance by competing corporations of an association to determine their rates of transportation..., the exchange of the stocks or property of competitive corporations for the stock or for interests in a single corporation, which thereby acquires the power to contrrl the rates of transportation or the pries of articles in interstate commerce in which the corporations were dealing... are alike declared to be illegal by this law...79/

77/ 26 Stat. 209 (1890), 15 U.S. Code Section 1 et seq.

78/ United States v. Standard Oil Co. of New Jersey, 173 Fed. 177 (Cir. E.D. Mo. 1909).

79/ Ibid., p. 184-5.

This observation confirms the notion that the Sherman Act was perceived as a means of regulating monopolistic advantages in transportation, including oil pipelines. Thus, the Sherman Act existed along side the Hepburn Act as the second basis of regulating oil pipeline activity. Monopolistic practices were regulated by the Sherman Act, and the Hepburn Act established rate regulation, but it should be observed that the two were not mutually exclusive in jurisdiction.

On appeal, the Supreme Court of the United States affirmed the Circuit Court in Standard Oil and thereby established a landmark antitrust decision.80/

Apart from the Standard Oil suit, the Federal Government has not successfully undertaken major litigation under the Sherman Act to bring about the divestiture of oil pipelines from oil conglomerates. Standard Oil continues to be an almost singular judicial attempt at vertical divestiture in the oil industry.

The first major enforcement action initiated against oil pipelines under the Hepburn Act began as an inquiry of the Interstate Commerce Commission in June 1911 to determine whether any of the rates and practices of several named oil companies were in violation of the Act. At the completion of the inquiry, the ICC ordered the pipelines to begin filing schedules of rates and charges for transportation of oil.81/

The pipelines appealed to the Commerce Court arguing that the Hepburn Act only applied to pipelines which voluntarily acted as common carriers and that the Act was an unconstitutional denial of due process and a deprivation of

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80/ Standard Oil Company of New Jersey v. United States, 221 U.S. 1 (1911).

81/ In the Matter of Pipe Lines, 24 I.C.C. 1 (1912).

property without just compensation in violation of the Fifth Amendment. In Prairie Oil & Gas Co. v. United States,82/ the Commerce Court had difficulty dealing with the constitutional arguments and in part agreed with the pipelines.

All of the issues in that case came to the Supreme Court in the Pipe Line Cases 83/ in June of 1914. In a brief opinion for the Court running less that five total pages most of which were devoted to a description of Standard Oil business practices, Mr. Justice Holmes concluded that the intent of the Hepburn Act was to bring under its regulation interstate oil pipelines regardless of their prior status:

> ...while the amendment [the Hepburn Act] does not compell... [oil pipelines] to continue in operation it does require them not to continue except as common carriers.84/

On the constitutional issues, Holmes was even more cursory:

> There is no taking and it does not become necessary to consider how far Congress could subject them to pecuniary loss without compensation in order to accomplish the end in view.85/

Although there have been other Supreme Court determinations on many of these same constitutional issues relating to oil pipelines,86/ the view established by Justice Holmes continues to support the Hepburn Act.

82/ 204 Fed. 798 (Commerce Court 1913).

83/ The Pipe Line Cases, 234 U.S. 548 (1914).

84/ Ibid., at 560.

85/ Ibid., at 561.

86/ See Valvoline Oil Co. v. United States, 308 U.S. 141 (1939); Champlin Refining Co. v. United States, 329 U.S. 29 (1946); and, United States v. Champlin Refining Co., 341 U.S. 290 (1951).

As common carriers under the Hepburn Act, oil pipelines which were "shipper-owned" have unique problems in the establishment of nondiscriminatory rates. Rates must be just and reasonable87/ and rebates are prohibited.88/

The problem of rate establishment by oil pipelines shipping their own oil and "shipper-owners" was first raised in a 1941 suit brought under the Elkins Act89/ to enjoin certain shipper-owner pipelines from granting refunds, rebates, and offsets against regular tarrif charges for oil transportation. The complaint, brought by the Department of Justice, alleged that returns on the shipments of oil owned by Atlantic Refining (and several other pipelines) in its own pipeline amounted to an illegal rebate.

The case was settled with the approval of the court by means of a consent decree which provided in paragraph III that "no defendant common carrier would credit, give, grant, or pay directly or indirectly... any earning, dividends, sums of money or other valuable considerations derived from transportation or other common carrier services which in the aggregate is in excess of its share of seven percentum (7 percent) of the valuation of such common carrier's property, if such common carrier shall have transported ...petroleum products for said shipper-owner."90/ Valuation was intended to mean the latest final valuation of the common carrier's property owned and used for common carrier purposes as established by the ICC.

87/ See, 49 U.S. Code Section 1(4) and (5) (1976).

88/ See, 49 U.S. Code Section 2 (1976).

89/ See, 49 U.S. Code Section 43 (1976).

90/ United States v. Atlantic Refining Company, Civil Action No. 14060, U.S. District Court for the District of Columbia (December 23, 1941).

There are several points which might be generally made about this consent decree. First, by its own language, the consent decree is applicable only to defendant common carriers. Therefore, it would seem that non-defendant common carriers, or perhaps sucessors in interest, are not bound by the express terms of the consent decree.

The ICC was neither the complaining party, or a named party, as the Elkins Act requires that action be brought by the Department of Justice, and there is nothing in the consent decree which imposes any obligation on the ICC. Therefore, as a matter of law, the legal criteria for the actual estblishment of rates is unaffected by the consent decree.91/ And, even though earnings in excess of the 7 percent figure may not be returned to the parent by the shipper-owned carrier, the earnings may be retained under the consent decree. The 7 percent return on valuation was not established by the settlement decree as the basis for the approval of rates to be charged. In other words, the ICC was permitted to continue to establish rates that were "just and reasonable," even though earnings resulting from such rates might exceed the 7 percent figure. Earnings could be retained and used for several purposes as provided in the consent decree.

In 1959, the Supreme Court reviewed a case brought seeking an interpretation of this consent decree. In its review, the Supreme Court gave its approval to the system of limitation imposed by the consent decree.92/

91/ See, statement of Victor Hansen, Assistant Attorney General in charge of the Antitrust Division. "Consent Decree Program of the Department of Justice," Hearings Before the Antitrust Subcommittee of the House Judiciary Committee, 85th Cong., 1st Sess. (1957), Part I, Volumes I and II, "Oil Pipelines," at 4476.

92 / United States v. Atlantic Refining Co., 360 U.S. 19 (1959).

The question presented to the Court was an interpretation of the means of computing the valuation of pipelines under the 1941 consent decree. The following excerpt from the case summarizes the issue raised:

> From 1941 to 1957 appellees computed allowable dividends by taking 7 percent of the valuation of pipeline property and then giving each owner a proportion of this sum equal to the percentage of stock it owned. In 1957, however, the Government brought this suit against appellees claiming that the pipelines were giving, and the shipper-owners were receiving, dividends in excess of those allowed by the decree. The Government did not contest the valuation figures used, but argued, despite the language of the decree, that only a part of 7 percent of the valuation could actually be made available as dividends to stockholders. The total allowable "dividends," it claimed, would have to be shared between stockholders and creditors. The stockholder's (shipper-owner's) "share" of the carrier valuation, so the argument ran, was to be the proportion which stock-investment in the carrier bore to the carrier's total invested capital (including debt owed to third persons). Seven percent stockholder-dividends could only be computed out this "share" of the sum, and could then be distributed to each shipper-owner in proportion to its individual stock interest. Only in this way, the Government contended, could the consent decree's aim of preventing disguised rebates be accomplished. For only in this way would dividends be limited to a "fair" sum: 7 percent of the current value of what each owner had invested in its subsidiary. The trial court rejected the Government's interpretation, and the United States brought a direct appeal under 32 Stat. 823, as amended. 15 U.S.C. section 29, 49 U.S.C. section 45. 93/

The Supreme Court rejected the Government's position. A hypothetical example illustrates the difference in interpretation, including the Government's view which was rejected.

> Assuming a carrier has an I.C.C. "Valuation" of $10,000,000, $2,000,000 of which represents stock investments of $1,000,000 by each of two shipper oil companies, and $8,000,000 of which represents debt because of money borrowed by the carrier from others, on the appellee-companies' interpretation of the decree, each of the two shipper-owners would be entitled to "dividends" of one-half ($1,000,000/$2,000,000) of 7 percent of $10,000,000 or $350,000. On the Government's new interpretation instead,

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93/ Ibid., at 21.

> each shipper-owner's "share" would be one-tenth ($1,000,000/$10,000,000) of 7 percent of $10,000,000 or $70,000, this being 7 percent of each one's actual investment of $1,000,000 in the company.94/

In essence, this interpretation allowed the common carriers to distribute earnings on pipelines' operations based on valuation which included borrowed money, including money borrowed from the parent. As one House Subcommittee report put it:

> The decree, entered on December 23, 1941, largely abandoned the original theory of the complaint that any dividends to shipper-owners were illegal rebates and instead sought only to limit dividends to a fair return on the actual investment by shipper-owners. But it did so quite ineptly by the adoption of a formula limiting dividends paid out to 7 percent of the "shipper-owners's share" of the pipeline's "valuation." This language made the 7 percent limitation almost completely ineffective, since it was applied not to paid-in investment only but to the entire valuation of the line, including debt capital. And since joint venture pipelines were increasingly financed by a 90 to 10 debt-equity ratio, the difference was quite staggering. Instead of a limit of 7 percent of actual investment, the formula permitted dividends of 70 percent of actual investment.95/

Because Atlantic Refining continues to stand as the major precedent relating to shipper-owned pipeline valuation, oil pipelines appear to enjoy a very unique form of economic regulation. Although they are "common carriers" under the Federal statutes, they are treated differently from common carriers as that term is used in general legal discussion.

And since the rate-making mechanism is divorced from other types of economic and antitrust regulation, the picture of oil pipeline regulation at the Federal level is fragmented.

94/ Atlantic Refining, supra, footnote 2 at 22.

95/ See, Anticompetitive Impact of Oil Company Ownership of Petroleum Products Pipelines, A Report of the Subcommittee on Small Business Problems to the Select Committee on Small Business, House of Representatives, 92d Cong., 2d Sess. (1972), at 8.

In its efforts to consolidate all of the major Federal energy regulatory functions under a single agency, the Congress provided in the Department of Energy Act96/ for the transfer of Federal oil pipeline regulatory authority to the new Department of Energy. Functions relating to rates and charges for transportation of oil were transferred to the Federal Energy Regulatory Commission (FERC), which is an independent commission organized within the Department of Energy. This transfer combined oil and natural gas pipeline authority for the first time in a single agency, FERC.

Since its establishment in 1977, FERC has continued with the oil pipeline rate investigation and valuation proceeding initiated by the ICC shortly before the DOE Act.97/ While many important issues could ultimatly be resolved in that extended prodceeding, perhaps the most significant recent event is the initiation of a suit by the Department of Justice to dissolve the consent decree entered into in Atlantic Refining. In a suit filed on November 16, 1981, the United States seeks to set aside the consent decree in its entirety because it no longer advances the public purposes for which it was entered.98/ If the courts do permit dissolution of the consent decree, no legal limitation on pipeline distributions to parent owners, and no limitation on rebating, would exist. It should be obvious that the issues involving common carrier status for natural gas pipelines will be similar to those which continue to be raised in connection with oil pipelines. Two principal questions are raised:

96/ Public Law 95-91, 91 Stat. 565 (August 4, 1977).

97/ See, Farmers Union Central Exchange v. Federal Energy Regulatory Commission, 584 F.2d 408 (D.C.Cir. 1978), cert. denied, 99 S.Ct. 596.

98/ United States v. Atlantic Refining, Civil Action 14060, U.S. District Court for the District of Columbia, suit filed November 16, 1981.

1) matters of access to pipeline capacity and 2) matters of valuation and rate regulation of pipelines which are primarily owned by major producers shipping their own commodities.

These issues are likely to arise with regard to natural gas pipelines in connection with, and after, wellhead decontrol. But it appears that common carrier regulation offers no simpler mechanism for dealing with these two issues than does the traditional utility regulation approach to interstate natural gas pipelines. In fact, it raises other issues. Oil pipelines are not required to obtain Federal approval by means of a certificate of public convenience and necessity before operations. Neither are they subject, as are natural gas pipelines, to adequate service obligations. Exit from the industry and termination of operations by oil pipelines is also not Federally approved, as are such actions by gas pipelines. Thus, possible common carrier status for natural gas pipelines raises important issues. Such status may not be appropriate because of differences between the oil and gas industry and because of the troublesome experience of oil pipelines regulated as "common carriers".

Moreover, it may be that the precipitous modification of natural gas pipeline regulation without advanced consideration of rate and access issues might create a regulatory climate to encourage greater production and transportation integration in the industry. Favorable regulatory incentatives, such as those governing oil pipeline operation, might quickly encourage a similar industry structure to that of the oil business.

If, on the other hand, interstate natural gas pipelines remain owners of natural gas purchased from producers for the purpose of selling to distributors as under the current scheme, decontrol at the wellhead may require an examination of the purchase transaction practices of pipelines. Limitations on the nature of escalator clauses in natural gas purchase contracts, limitations on certain take-or-pay obligations to producers, and other contract features which impose burdens on pipelines and increase prices might be eliminated, or proscribed, in order to assure that pipelines engage in arm's length purchase transactions which provide needed and adequate long-term supplies of natural gas at the lowest possible price.

The supply obligation imposed by law under the Natural Gas Act leaves pipelines with little incentative to bargain for low prices because their principal legal obligation is to obtain adequate supplies. Thus, in the face of wellhead decontrol two issues are raised:

1) who should be able to ship gas in a pipeline?

2) and at what price?

Congressional declaration of the types of contracts which may be entered into without specifying price may at least provide important assisance in permitting accurate market signals to be transmitted through the pipeline to producers.

Finally the question of emergency operation and inadequate pipeline capacity should be briefly treated. Natural gas pipelines at present must receive approval to engage in, and terminate, operations. During emergency periods of high natural gas demand, it may become necessary as in the past to allocate supplies among a given pipeline's customers to direct supplies to needed services. Many of these authorities are curretly provided for under the Natural Gas Policy Act of 1978, and their modification in the form of pipeline decontrol could result in the inability at the Federal level to deal with emergency natural gas service, an activity which may be beyond practical state reach.

Thus, the position of the pipeline in the middle of producers and distributors results in a situation where pipelines face potential repercussions from wellhead decontrol possibly involving greater state regulatory controls on both ends of the pipeline. The added notion of pipeline decontrol makes evaluation of the result most difficult, but does indeed raise many important issues.

Distibution Regulation. Because local distribution company transactions in the purchase of natural gas from interstate pipelines and otherwise in interstate commerce are subject to regulation under the Natural Gas Act, the proposed decontrol of wellhead prices raises issues regarding the proper role of regulation of distribution. The monopolistic geographical franchises accorded local gas distribution companies is the fundamental reason for state retail distribution and rate regulation. Irrespective of the nature of wellhead regulation, it seems unlikely that the need for this local regulation will be found now to have lessened. However, the question of whether stricter scrutiny of purchase transactions by distribution companies is desireable in a new regulatory environment of Federal wellhead decontrol may be raised over concern about the vacuum left by decontrol.

Whether states may constitutionally set a ceiling price paid by a local distribution company for gas purchased in another state in the absence of Federal pricing controls remains open. Thus, efforts at more extensive retail regulation may result in states which consume large amounts of natural gas. And, if states producing natural gas undertake significant wellhead price regulation themselves, consuming states may well respond in kind with more expansive retail rate regulation.

There are indeed numerous consitutional decisions which might be cited in one fashion or another in an attempt to posit a precise delineation between state police powers and the Commerce Clause dealing with the issue of the extent to which state may regulate in the absence of Federal regulation. Although many of the cases provide some guidance with regard to historical constitutional interpretations, the full range of possible state legislative actions which might occur upon Federal wellhead decontrol is not clearly charted by precedent.

For example, the relatively recent efforts of states, during the period of oil price controls under the Emergency Petroleum Allocation Act, to provide certain protections to independent gasoline stations have been upheld in Exxon Corp. v. Governor of Maryland.99/ The State of Maryland had enacted a statute which provided that a producer or refiner of petroleum products could not operate a retail service station within the state and that such producer or refineer must extend "voluntary allowances" to all retail stations supplied with products.

The statute was challenged as violating the Commerce and Due Process Clauses of the Constitution and as having been federally preempted by the Clayton Act, as modified by the Robinson-Patman Act. In addressing the Commerce Clause issue, and in eventually upholding the statute as valid, the Court made this important observation:

> Finally, we cannot adopt appellant's novel suggestion that because the economic market for petroleum products is nationwide, no State has the power to regulate the retail marketing of gasoline. Appellants point out that many state legislatures have either enacted or considered proposals similar to Maryland's , and that the cumulative effect of this sort of legislation may have serious implications for their national marketing operations. While this concern is a significant one, we do not find that the Commerce Clause, by its own force, pre-empts the field of retail gasoline, marketing. To be sure, "the Commerce clause acts as a limitation upon state power even without congressional implementation."...But this Court has only rarely held that the Commerce Clause itself pre-empts an entire field from state regulation, and then only when a lack of national uniformity would impede the flow of interstate goods...The evil that appellants perceive in this litigation is not that the several States will enact differing regulations, but rather that they will all conclude that divesti-

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99/ 437 U.S. 117 (1978).

> ture provisions [such as those at issue here] are warranted. The problem thus is not one of national uniformity. In the absence of a relevant congressional declaration of policy, or a showing of a specific discrimination against, or burdening of, interstate commerce, we cannot conclude that the States are without power to regulate in this area. 100/

Thus, the Court has only recently rearticulated the broad constitutional principles with regard to the scope of state authority and intrusion upon the Commerce Clause in the specific context of retail regulation of petroleum products, leaving open the seemingly close analogy to natural gas.

It appears clear from the foregoing analysis that the Natural Gas Act may have operated to preempt certain limited state regulatory activities. Following the termination of Federal wellhead price controls, those broad percentage powers to regulate both the production and marketing of natural gas may once again devolve upon the states.

Some Observations

Proposals to decontrol Federal wellhead ceiling prices for natural gas, in whole or in part, raise a significant number of legal issues. Perhaps the most significant category of issues goes to the heart of Federal-state relations, and deals with the extent the states may be able to undertake a variety of forms of regulation of various segments of the natural gas industry once the Natural Gas Act and the Natural Gas Policy Act of 1978 are no longer impediments to state action.

These regulatory issues go to the very basic structure and history of the natural gas industry as it has evolved over nearly a half century of Federal regulation. While the purpose, here, has been to identify a few of the major

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100/ Ibid., at 128-129.

legal issues, the importance of these issues is such that thorough consideration of decontrol and its ramifications is necessary.

Few of the specific regulatory events which might affect various components of the natural gas industry can be completely described, but they can indeed be anticipated. Significant modification of Federal wellhead controls, without clear delineation of state powers, will undoubtedly invite some unwanted state actions, and may have enormous influence in the further development and evolution of the natural gas industry.

Action on wellhead decontrol should anticipate as thoroughly as possible all the likely legal and regulatory consequences.

CHAPTER V

TECHNOLOGY, NATURAL MONOPOLY AND REGULATION*

An Overview of Technology

Natural gas can be considered as a modern fuel, although its availability has been a matter of conjecture for centuries. Its first use in the United States was in 1821 in Fredonia, New York. From that beginning an industry involved in production, processing, transportation, and sales has sprung up.

The gas occurs in the pores of various rock formations. It is obtained by drilling wells into the strata containing the fluid. Assuming the rock has adequate porosity and permeability, the gas will flow up the well, through a system of valves, and into the gathering lines. The latter is a system of pipes through which the gas or gas-oil mixture is transported to a processing plant. Generally, the gathering lines operate at fairly low pressures, which are sustained by pumps or simply by the wellhead pressure itself.

At the processing plant the oil and other non-gas products, plus a number of impurities are removed from the gas.1/ The size and configuration of the processing plant depends to a great extent upon the composition of the mixture coming from the wells in each field. Clean, dry gas can be shipped directly. Even where it is not mixed or dissolved in petroleum, however, natural gas is very frequently accompanied by a variety of economically valuable hydrocarbon products plus a number of contaminants. The hydrocarbon products are collectively termed natural gas liquids. These include a variety of fluids that exist in liquid form at the relatively low pressures commonly associated with natural gas wells. Some of these are liquid at atmospheric pressures, but all are highly volatile. Natural gas liquids include propane, butanes, natural gasoline, ethane, and other petroleum products which are distinct from methane and the other lesser gases that comprise natural gas. The natural gas liquids have considerable economic value of their own and are marketed for a variety of purposes. Propane, of course, is widely used in place of natural gas in rural or other areas where natural gas distribution is unavailable.

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1/ For a more detailed discussion of contaminants and technology see Appendix IC.

A number of contaminants are commonly associated with natural gas, including sulfur compounds (which are often purified and sold), carbon dioxide, and various oxides of nitrogen. The sulfur compounds must be removed because they will corrode pipelines and machinery and can pose an environmental hazard if released, while carbon dioxide and nitrogen oxides can degrade combustion by reducing the heat content of the gas. Processing plants are designed to reduce these contaminants to acceptable levels and to separate the natural gas liquids for other uses.

Another serious contaminant of natural gas is water vapor, which may be converted under the high pressures in transmission pipelines into a variety of chemical hydrates. These hydrates are solid substances that can lead to clogging of pipeline hardware and, therefore, must be removed. Processing plants use a variety of dehydrating processes to remove water vapor, and occasionally use various inhibitors such as methanol to trap the water molecules so that they are not available to form hydrates.

Finally, there remains the problem of separating the gas from any oil that may be present.2/ Oil, if permitted to enter a gas transmission line, can

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2/ Of the 21.48 Tcf of the Natural Gas produced in 1980, 3.78 Tcf was from oil wells and 17.70 from gas wells. See Energy Information Administration, 1980 Annual Report to Congress, p. 103.

constrict flow and clog pumps and valves. Similarly, gas which contaminates petroleum pipelines can produce vapor lock and other serious problems. Thus, it is essential that the petroleum and gas be separated. A wide variety of methods may be employed, depending upon the quantity of oil present, its viscosity, and other physical considerations. One common technique consists of sending the oil-gas mixture through a series of filters or baffles that are permeable to gas but not to the associated oil. The latter is condensed and/or collected in the bottom of the apparatus and drained away for other use.3/

After the gas has been separated from other marketable fossil fluids and purified of other contaminants, it is ready for pipeline shipment. It is compressed at a compressing station for injection into the transmission pipeline. This serves to reduce the volume of gas and to push the gas through the pipeline.

Typical pressures generated by compressor stations for natural gas pipelines range as high as 1300 pounds per square inch (psi), although 1000 psi is more common. Rather than having one compressor station at the beginning of the pipeline, it is more efficient in terms of transmission costs to have compressor stations at regular intervals along the transmission line. For long transmission lines, compressor stations might typically be spaced at about 75 mile intervals. In a typical transmission line, the first compressor station might inject gas into the line at a pressure of 1000 psi. As it is injected into the line, the entering gas must necessarily displace the gas that is already in the line. It does so by pushing that gas forward from the high pressure region near the compressor station toward the lower pressure regions

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3/ The methods available for each of these types of gas processing are quite varied. Those interested in greater information on any of these subjects might want to consult American Gas Association. Gas Engineers Handbook. New York, Industrial Press, 1965.

further down the line. There is often a drop in pressure of about 3 psi per mile of line, and it is this pressure drop that maintains the flow of gas in the forward direction. Typical flow rates might be about 15 miles per hour; at pressures of 1000 psi the gas is compressed to about 1/70 of its normal volume at standard temperature and pressure. Thus a long distance transmission line might be designed to permit a pressure drop from about 1000 psi at the output of each compressor station to about 800 psi at the input of the next compressor station, where the gas would be repressurized to 1000 psi.

This is not to say that the gas would not flow through a transmission line without being repressurized at regular intervals, but rather that much larger volumes of gas can be transported with such repressurization in the same size line. For instance, the first gas transported via pipeline to the east coast from East Texas was through two pipelines originally constructed during World War II for the shipment of petroleum and refined petroleum products. During the first few months of natural gas operation, no compressor stations were employed; the 800 psi wellhead pressure of the fields in Texas was sufficient to push the gas all the way to Pennsylvania. When 21 compressor stations were added to the system, however, the total delivery capacity increased from 140 MMcf to 435 MMcf per day.4/

The capacity increase afforded by compressor stations is extremely important to the profitability of any transmission system, because the major costs of such systems are the fixed costs resulting from pipeline construction. The additional expense of building the compressor stations is more than compensated for by the increased capacity that results; the costs of operation of the compressor stations is not highly detrimental to the overall economics

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4/ See U.S. Federal Power Commission, National GAs Survey, Vol. I.

of the system even at today's energy prices, particularly because the regulatory process allows these costs to be passed through to customers.5/ Compressor stations are generally powered by the combustion of a small fraction of the gas contained in the pipeline and are controlled remotely from a central point. Thus, most compressor stations are operated without permanent staff on location.

Though the dynamic elements of any natural gas transmission line are the pipeline and the compressor stations, there is often a third element of great importance to the efficient technical operation and profitability of the system. This is the gas storage field. Gas storage fields have been increasingly employed since about 1930 as a means of: 1) maintaining pipeline operation at or near full capacity during periods of low demand, and; 2) supplying peak load demands, generally during the winter months, without having to expand transmission pipeline capacities. The avoidance of unused pipeline capacity is economically important because transmission pipelines are capital intensive operations.

It is commonly estimated that it takes about $1.50 to $2.00 of investment in transmission pipeline facilities to generate $1.00 in annual sales, although reliable and accurate figures are not available for transmission pipelines per se because of the highly varied activities and investments of the companies that own the pipelines.6/ In addition to the pressures of capital intensity, it is not uncommon for gas producers to insist on "take or pay" contracts requiring that a set amount of gas be paid for by the transmission company

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5/ Ibid. Also see current engineering texts on the Economic Advantages of High Pressure Transmission. One such would be the American Gas Association's Gas Engineers Handbook, The Industrial Press, New York, 1965.

6/ Private conversation with Ms. Georgie LeDakis, FERC Official.

whether it is accepted for delivery or not.7/ Thus it is essential that pipelines be operated at capacity insofar as is possible.

Quite apart from the economics of the situation is the fact that the pumping machinery in the compressor stations functions best if it is operated within a narrow range of load. While it is possible to turn some of the pumps on and off to accommodate load variations, there are limits to the range of effective machinery operation. Thus both the economics and the technical operation of a pipeline provide incentives for full capacity operation at all times. Unfortunately, the demand for natural gas in both the commercial and residential sectors is highly cyclical through the year, with demand during the colder months being much higher than in the warmer months.

Until storage fields came into use, the only means of leveling the delivery rate of pipelines was to encourage large industrial use of gas during off-peak demand periods by offering low prices in return for interruptible service. Although the gas shortages of the past ten or fifteen years have caused less reliance to be placed on such interruptible load sales, the practice continues but is now augmented by use of an extensive gas storage system that is filled during off-peak demand periods. Storage is accomplished by pumping gas into a subsurface geological structure — most usually of natural origin, such as a depleted oil or gas field, a salt dome, or an aquifer. In some cases, abandoned coal mines and various non-porous rock formations have been used.

Most pipelines are now operated at close to capacity, using natural gas storage reservoirs to balance supply and demand. Excess gas is pumped into storage during periods of low demand, and then removed to augment deliveries when demand exceeds pipeline capacity. The easternmost storage areas lie in

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7/ U.S. Federal Power Commission, National Gas Survey, v. I., pp. 42-3.

the Appalachian Mountain region, two or three hundred miles from the major Eastern markets. Even with that disadvantage, however, storage reservoirs permit gas supplies to be momentarily expanded beyond the delivery capacities of either the gas fields or the major portion of many long distance gas pipelines. In 1980, some 6.27 Tcf of gas was in storage, of which some 2.64 Tcf was available for peaking demand while the rest of the gas remains in the ground to sustain adequate pressure for delivery of the "working gas".

At the far end of the natural gas transmission lines lie the distribution systems which actually serve the gas customers in an assigned region. In contrast to petroleum pipelines, whose transported wares are later transshipped to other destinations as needed, gas pipelines serve only carefully designated geographical regions. They are tied to certain distributors whom they supply on a continuing basis. This would seem to be the inevitable and necessary result of the fact that natural gas cannot be readily shipped except by pipeline unless it is liquified at considerable additional expense and transported in special containers capable of maintaining temperatures below about -265°F, or -165°C. Although the technology for such liquifaction and low temperature shipment are now used for transoceanic shipment and storage of large amounts of gas at specially constructed depots on land, overland shipments of liquified natural gas are not widely employed because of the expense, the limited quantities that can be carried, and the safety problems involved.8/

8/ Liquified natural gas is trucked in limited amounts from seaport depots and liquifaction facilities to distribution facilities, most of the activity being in the North East. To illustrate the practical limits on such transport, truckload amounts range from about 600 to 800 Mcf, which is equivalent to the seasonal heat demand of about 7 typical detached houses (2000 sq. ft.) in the Boston area (perhaps 10 houses if they are built to the stringent standards proposed under BEPS), and even less houses in interior New England areas. Thus trucking of liquified natural gas is only practical (disregarding the added expense) to satisfy peaking demand.

Because of these limitations, natural gas pipelines are "tied" at both ends: there are definite suppliers who produce the gas under long term contract arrangements at the "input" end of the line, and the gas is sold to specified distributors at the "receiving" end. The customer's burner tip is literally at the end of a continuous series of pipe that begins at the wellhead. While there is, on occasion, some gas shunted from one pipeline to another to meet emergency situations when unexpected shortages or breakdowns occur -- this being possible because pipelines often parallel each other even though they serve different regions -- this is only by special arrangment. Producers in the gas fields may provide gas to several pipelines, but each distribution area is supplied by a limited number of transmission pipelines.

In serving a region, distribution companies must maintain storage facilities, not only for a certain quantity of natural gas but also for a variety of other gases. The latter are more expensive to use than natural gas, but can often be stored locally in liquified form.9/ For instance, on about half of the days of the year it is necessary for many distributors to augment their natural gas from pipelines with synthetic naphtha gas. On 20 or 30 days of the winter, the pipeline and synthetic gas will be augmented with liquified natural gas. Perhaps demand will be so very high on the coldest days of winter that these other supplies will have to be augmented with propane gas, the most expensive of the gases commonly employed. Thus, gas distribution systems perform a complicated operation of load leveling and of maintaining adequate supplies to meet demand. Much more is involved than simply buying gas from a pipeline company and reducing pressures for local consumption in homes, commerce and industry, although that is an important function in itself.

9/ U.S. Federal Power Commission, National Gas Survey, p. 47.

Occasionally, distribution companies are called upon to undertake collective action to overcome special problems. One recent example[10] occurred when storms delayed the arrival of ships delivering liquified natural gas from Algeria, and thereby created a very serious shortage of gas in one New England distribution area. The pipeline serving the area lacked the capacity to increase its sales to the affected area without a compensating decrease elsewhere. Under the coordination of the Federal Energy Regulatory Commission and the officials of the pipeline involved, those distributors along the pipeline having ample gas in storage for emergency use agreed to make use of their reserve supplies to reduce their "take" from the pipeline, thereby making more gas available to the affected area. Had this arrangement not been possible, the consequences for the affected area would have been quite serious since much of the gas used in that area was employed for home heating.

In recent years a variety of events have prompted greater diversification of activities of both pipelines and distributors, partly to ensure the future availability of adequate gas supplies. Pipeline firms, of course, have a long history of involvement in production activities. Where distributors were once the only producers of artificial and synthetic gases, pipeline companies have begun to enter the field in strength. And while some distributors are following the lead of the transmission companies and are importing liquified natural gas directly, and a few are already laying plans to manufacture synthetic gas from coal and municiple wastes for standard or base load (as opposed to peaking) use, pipeline companies are also beginning to examine the prospects of manufacturing large amounts of high Btu gas from coal. A few distributors are even exploring for, and developing, their own natural gas supplies, which they ship to their home areas by special arrangement with existing pipeline companies. Thus the standard distinctions between producers, pipeline firms, and distributors are being blurred.

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[10] Williams, Kenneth. FERC Official, in a briefing. Washington, D.C., Nov. 6, 1981. The distribution company most seriously affected was Boston Gas Company, though others also experienced difficulty.

Technology and Natural Monopoly

As these changes occur, the behavior of the natural gas industry is conditioned to a considerable extent by limitations, technologic particularly for gas transportation. Two facts are central: 1) the only practical and efficient means of overland transport of natural gas for base-load demand is via pipeline, and 2) pipelines are capital intensive, immobile, and capable of optimally efficient operation only within a relatively narrow range of delivery rates. In considering the attributes of the current regulatory apparatus, and how that apparatus might be changed, it is important to remember that the present regulatory structure was designed to be compatible with the technology for gas transportation. Thus, some of the behavior of the natural gas industry that might seem to result from regulation is, in fact, the product of technological limitations -- particularly those just mentioned. As a result, changes in regulation, or the elimination of regulation, of the natural gas pipelines might not produce some of the behavioral changes in the industry that might be expected.

Although there are a number of inherent differences between the technologies used for natural gas and petroleum pipelines, these differences are relatively insignificant compared to the tremendous physical and technical similarity between petroleum and natural gas pipelines. In fact, the two types of pipeline systems are fundamentally the same except for the fact that one is designed to transport a liquid and the other a gas. The post World War II conversion of the Big Inch and Little Inch pipelines from petroleum crude and refined petroleum product transmission to natural gas transmission, as mentioned above, would seem to illustrate that point rather clearly. Thus, technological differences between petroleum and natural gas pipleines do not appear to mandate the differences that existin in the way in which they are regulated.

The fundamental reason for regulating natural gas pipelines as natural monopolies is that pipelines offer the only method of transporting natural gas via overland routes in commercially important quantities needed for base loads at costs that are economically attractive and with an acceptable degree of public safety. The basic problem is that natural gas at atmospheric pressure has a rather low energy content per unit volume, so that a great deal of gas has to be supplied in order to convey meaningful amounts of energy. For instance, about 125.5 cubic feet of natural gas (at room temperature and one atmosphere pressure) contains the same amount of energy as a gallon of gasoline. This means that it would take a cubical container five feet long at each edge to hold enough gas to convey the same energy as a gallon of gasoline, which can be contained in a cube only six inches on each side. Or, to put it another way, natural gas at room temperature and atmospheric pressure has about 940 times less energy per unit volume than gasoline. Therefore, natural gas cannot be transported on a practical basis via tank cars or trucks because the required containers are far too large. Even if natural gas is pressurized to about 1500 psi and compressed in volume, it still has only about one-tenth of the energy density of gasoline. At this low energy density it is still not attractive to attempt shipment of pressurized natural gas on a commercial basis except via pipeline. The expenses of compressing the gas and of building high pressure tanks of large volume in which to ship the gas, the large weight of the pressure tanks themselves, and the concern for public safety in the event of a leak, all combine to make non-pipeline pressurized shipment unattractive at this time.

Although the technical difficulties of shipping natural gas in containers becomes less negative if the gas is liquified, economic, safety, and volumetric factors limit the amounts that can be transported in practice. When natural gas is liquified, it has about two-thirds of the energy density of gasoline (or of fuel oil). As a result, liquified natural gas has begun to be transported on oceangoing ships with specially designed tanks for low temperature storage. The economics of such shipment can be attractive for certain gas uses at the present time, and thus several port facilities have been constructed in the United States to receive liquified natural gas imported from overseas. However, the safety problems are still a matter for concern, and the ships carrying liquified natural gas can only enter harbors under extreme precautions. Where liquified natural gas is shipped overland, the probability of accidents resulting in a rupture of the storage containers on trucks or tank cars is higher. Because of the extreme volatility of liquified natural gas, its explosive and/or combustive power is a matter for careful consideration, if not definite concern, because the liquid is rapidly converted into large quantities of combustable gas if its temperature rises. Safety problems are less serious where liquified natural gas is stored in tanks on land. In that case, precautions can be taken to contain the leakage of liquid and to provide for the rapid extinguishing of fires. The Gas Engineers Handbook11/ states that fires in properly designed storage facilities are somewhat easier to extinguish than gasoline fires, though their heat radiation levels are higher. Nevertheless there is an historical record including serious fires at liquified natural gas storage sites.

11/ American Gas Association, Gas Engineers Handbook, p. 303 ff.

The inflexibility of transportation systems for natural gas was therefore an essential factor in the way that natural gas transmission systems came to be regulated. From the earliest uses of natural gas for home, commercial, and industrial purposes until the 1930s -- and perhaps the 1940s -- natural gas was a commodity in need of a market for lack of transportation. In most cases, gas was discovered by chance in connection with attempts to find oil, which had far greater commercial value. Tremendous amounts of natural gas were vented or flared because of a lack of any market within possible reach of an existing pipeline. Until the mid-1920s, when long distance pressurized lines became technically feasible there was no way for gas to reach the potential major markets in the North and East. As a result, natural gas was generally only available in proximity to natural gas wells -- say a few hundred miles at most.

When natural gas was discovered in proximity to a promising market, and a pipeline and distribution system was built to market the gas, the common practice among producers and suppliers was to reap all possible profits as rapidly as possible. Local markets were generally expanded to the maximum extent, and the gas fields were depleted as quickly as demand and pipeline capacity would allow,[12] generally so that capital could be applied to further oil exploration. As a result, customers who had come to rely on natural gas often suffered a termination of service with little, if any, warning when a local field became depleted. This sort of behavior by natural gas companies focused attention on the need to stabilize supplies for each natural gas market that was developed. Had natural gas been able to be transported on a flexible and long distance basis, so that customers could have obtained new sources of supply as needed,

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12/ U.S. Federal Power Commission, National Gas Survey, v. I, chapter 2 and 4.

this irregularity of service might not have been a problem. As it was, the inflexibility of natural gas transmission and transportation became, and remained, the one fundamental factor that determined how and why natural gas transmission and distribution system were to be regulated.

Even after long distance pressurized transmission pipelines came into being, transportation inflexibility was the key factor that ultimately mandated regulatory action of a particular type. The situation, as outlined briefly in the National Gas Survey13/, was that many of the Nation's utilities came to be owned or controlled by a small number of holding companies. These holding companies controlled the electric and gas utility markets in many areas, and one of their major concerns was protecting their investments in manufactured gas facilities as natural gas pipelines began to spread across the country from Oklahoma and Texas after the mid-1920s. Since the advent of natural gas in a community might make facilities for the higher priced manufactured gas obsolete, the holding companies "... wanted to control the introduction of natural gas to the communities which they served and wanted to use natural gas initially to 'enrich' their manufactured gas"14/, whose energy content was only one-half to two-thirds that of natural gas per cubic foot. City officials and industry naturally wanted immediate availability of the cheaper high energy natural gas. The issue came to a head in 1932, to a large extent in consequence of the successful blocking of the construction of a pipeline being built from Texas to Detroit by the Panhandle Eastern Pipe Line Company. To stop construction, the Columbia Gas and Electric Company, which dominated much of the gas distribution business in Indiana, Ohio, Kentucky, West Virginia, and Pennsylvania, purchased

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13/ Ibid.,

14/ Ibid., p. 35.

controlling interest in Panhandle Eastern. The resulting protest by public officials and industrialists in Detroit, Chicago, Milwaukee, Cincinnati, Cleveland, Louisville, St. Paul, St. Louis and a number of smaller cities, led to a congressional investigation and the ultimate passage of the Natural Gas Act of 1938, the basic regulatory legislation to control the transmission and distribution of natural gas.

Had natural gas been able to be transported by some means other than by pipe, the entire holding company operation to inhibit use of natural gas could not have been attempted. It was the inflexibility of transportation of natural gas -- the fact that is could not be shipped by rail, barges, trucks, or other means that would circumevent the holding companies -- that made communities susceptible to the decisions and actions of those who coutrolled the pipes.

The Natural Gas Act reflected the inflexibility of gas transportation in a number of important respects. Principal among these was the recognition of a mutual responsibility between the gas transmission systems and the markets they serve. Thus the Natural Gas Act established the principle that a pipeline could not be certified for construction unless it could be demonstrated that the specific market to be served could be satisfied with certainty, and that no pipeline would be certified to serve a particular market unless it could be shown that the gas was actually needed.[15] Thus the pipeline company wishing to serve a new market would have to demonstrate 1) that it had delivery committments of gas from producers sufficient to satisfy demand and 2) that "public convenience and necessity" could be demonstrated for the proposed market area. Nor could a pipeline company abandon service without permission, so that once service was established there was a continuing obligation by the pipeline company. Further, pipeline companies could be ordered to service new markets in proximity to their systems if the Federal Power Commission could demonstrate that the additional service would not impair existing service to other communities and markets.

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[15] 15 U.S. Code, 717f.

In other words, in order to establish service to a new market, a pipeline company would have to specify the area to be served and demonstrate that it could satisfy demand, in return for which future competition would be limited until the conditions of public convenience and necessity required that new arrangements be made to care for additional demand. This regulatory approach was adopted in consequence of the inflexibility of natural gas transportation systems, and it served to establish natural gas pipeline companies as natural monopolies. In essence, then, it was not the character of the technology of natural gas transmission systems that led to monopoly regulation; rather, it was the limitations in the technology -- the lack of workable alternatives to pipelines -- that prompted the type of regulation that was adopted.

Technology and Institutions

The basic reliance on pipelines for the overland transportation of natural gas has a number of practical consequences that affect the structure of the natural gas industry. In contrast to the petroleum industry, where producers having wells in locations that are remote from refineries, pipelines, or railroads can still ship their product by trucks or ships (depending on location of the wells) and get it to market, the producers of natural gas have no practical and economically viable alternative to a pipeline connection between wells and markets. Since the cost of extending a pipeline to a new gas field can be significant, pipeline companies have a powerful incentive to negotiate favorable long term contracts with producers before making connections to a new field.

This ensures an adequate return on the investment necessary to extend the line and to construct processing and compressing facilities.

This incentive for long term supply agreements complements the incentive, or requirement, of the Natural Gas Act that pipeline companies be able to ensure continuous supply to the markets they are permitted to serve. It is also in addition to the definite financial incentive for pipeline companies to insure their own financial futures. Financial incentives alone, might not be sufficient to ensure that transmission pipeline companies would continue to operate in the public interest in the absence of regulation. There may well be competing financial incentives for pipeline companies to reduce or terminate service to those customers that are the most expensive, or least profitable, to serve. Remote customers, customers with the most cyclical demand -- such as are found in distribution areas with a high percentage of residential heating demand -- and customers with low total demand could be at risk in the absence of regulation. It cannot be said with certainty that the economic incentives that now exist for pipeline companies to plan for continuity of service will always endure in every possible situation that could arise, and that therefore the regulations requiring continuity of service are redundant and unnecessary.

Nevertheless, the economic incentives that now exist have a number of interesting attributes. For one, they make pipeline companies much more interesting in long term supply contracts (typically twenty years or more) than short term contracts, and much more interested in large new finds of natural gas than smaller finds. Though profits can be made from small petroleum deposits, discoveries of small natural gas deposits may have little value unless a pipeline is in close proximity to a number of small producers or a non-pipeline customer exists in the immediate vicinity.

This may tend to limit entry into the natural gas supply market somewhat, and it may affect the pattern of exploratory drilling in some cases. However, whatever limitations this may impose on the natural gas supply market would appear to be less significant than the consequences of long term supply contracts. These long term contracts may assure producers of stable production rates, and may assure pipeline companies of long term supply availability, but they tie producers, transmission companies, distributors, and customers to prices negotiated for each contract at a particular point in time. The natural gas supply conditions prevailing at that time, and the expectations for future supplies of natural gas at that time, may or may not be in accord with the future conditions that actually evolve. As a result, the "rolled in" price of gas to a pipeline represents a slowly changing ensemble of long term purchases. The effect of this may be insignificant in times when conditions remain fairly stable, but under current conditions of rapidly escalating prices for petroleum as a competitive fuel and at a time of great concern for future natural gas supplies, today's expectations of the future, as mirrored in current contracts and prices, could be "way off the mark". The result could be a serious distortion in future natural gas prices in the absence of wellhead price regulation.

It is the presence of these long term contracts that has produced the very unusual sort of markets, both at the wellhead and at the ultimate place of consumption, that are in evidence today. Where the price of petroleum is negotiated in some sort of current marketplace, albeit under the strong influence of (or domination of) OPEC, natural gas pricing reflects a long term historical integration of expectations for natural gas supplies and for natural gas demand in competition with other fuels. Many contracts currently in existence were negotiated at time periods considerably preceding recent efforts at price regulation. Significant quantities of the gas that is purchased by pipeline transmission companies today was contracted at prices negotiated during periods of abundant supply, and of low petroleum prices, in the early 1960s.

Since the advent of natural gas shortages around the start of the 1970s decade, and with the increased interest in natural gas as a fuel to replace higher priced petroleum products, there has been continuing market pressure toward increased prices for natural gas. This pressure has, of course, been checked by price regulations. However, natural gas producers have been insisting on a number of provisions in their sales contracts that have served to increase the current price of gas even under regulation, and which will automatically result in much higher prices when gas prices are decontrolled. These include such measures as 1) "Take-or Pay" provisions, which require pipeline transmission companies to pay for the full amount of gas stipulated in the contract to be delivered each month whether or not they actually take delivery; 2) "Favored Nation" provisions requiring prices of contracted gas to be increased to the levels obtained through new sales in a given field after deregulation is in effect; and 3) provisions that "index" the price of natural gas already sold under contract so that natural gas will assume a price per Btu equal to that of distillate fule oil or some other petroleum fuel. All of these measures are discussed in much greater detail in other sections of this report. However, their effect on natural gas pricing will extend far into the future, just as the low prices of the past persist today. They will tend to increase the price of natural gas to customers in future years no matter whether demand for natural gas increases or decreases.

The lack of a "current market" for natural gas would seem to have a number of highly possible and clear-cut implications, all of which result from the long term arrangements necessitated by the need for long term supply stability and by the high cost of connecting and processing new gas supplies. One consequence is that pipeline companies may feel somewhat insulated from immediate customer responses to sharply rising prices at the wellhead because customers see only the average, or "rolled in", prices paid for the gas they use. As a result, the impacts of higher prices for new gas purchase contracts are many years off in time and are not likely to be perceived as a matter of immediate primary concern to pipeline officials negotiating current contracts. Under today's perception that gas prices are going to rise sharply following deregulation, and that customers are going to accept that price rise for lack of acceptable alternative energy sources, the bidding for new supplies may be conducted at prices that are higher than those needed to bring forth new exploration and gas field development -- all of which is possible as a result of long term contracts and "rolled in" pricing. Nor is there likely to be serious pressure on pipeline negotiators to seek lower purchase prices: customer demand is not going to be influenced by the current prices being negotiated except in the very long term. Finally, under these conditions the negotiators on both sides of the purchase, for the producers as well as the pipelines, have the difficult task of seeking to negotiate reasonable and fair agreements without the benefit of consumer price response, which is the ultimate test of a market. When consumer price response finally arrives it is in response to price trends that have been established over a number of years, rather than over a few months or a year, producing consequences that cannot be corrected for years to come. Reasonable and effective negotiation for gas purchases is therefore difficult to achieve under the current system of the long term contracts mandated by the nature of pipeline regulation and by the limitations inherent in the transportation of natural gas by pipeline.

Since the current demand for gas is only loosely influenced by recently negotiated gas purchase prices, the entire market at the wellhead would seem to lack the responsiveness of the classical picture of the free market system. Demand for gas could rise or fall by a considerable amount without the price to the consumer being changed appreciably in response. In fact, under current regulation the response to declining demand might be to increase prices per unit volume gas in order to cover fixed costs, which would then have to be apportioned among fewer units of gas. Lacking some means of reducing gas purchase prices to meet falling demand, it is impossible to adjust prices to stimulate or sustain demand. Take or pay agreements would definitely work in increase the unit price of gas if demand were to fall, creating further difficulties. Thus, the consumer may be faced with a number of paradoxical responses to demand fluctuations, responses that are counter to classical market behavior in anything but the very long term, and which result in strong measure because of the strong incentives for pipeline companies to minimize changes in their connections to gas producing fields. Though the consequences might not be as serious as implied here, it is clear that the supply and demand relationships for natural gas are likely to be unusual because of the very long time delay created by long term contracts for the purchase of natural gas.

It would seem that if there were a greater diversity in transportation capabilities for natural gas, these long term purchase contracts might not have such a profound influence over negotiated prices and markets for gas at the wellhead. As it is, the limitations in transportation technology for natural gas has created an unusual relationship between gas producers and the transmission pipelines and would appear to have mandated economic arrangements that provide supply and demand. Current uncertainties about future supply, about the effects of deregulation of wellhead prices, and about future prices of competitive energy sources would seem to make it very difficult, under this market system, for pipeline companies to provide strong resistance to the desires of producers for price escalators and other contract provisions of the type indicated above.

Turning to look in the opposite direction, it would appear that similar inflexibilities in the mobility of pipelines and the great expense of pipeline construction mandates fixed long term relationships between pipeline companies and distributors. The result is that distributors cannot shop around for gas supplies in any real sense, and there is very little that a distributor can do to obtain lower prices.

Technology and Regulation

In a very real sense, the regulators have been designated to represent the natural gas consumers in the marketplace because of the impossibility of having competition betwen distributors as a result of the mechanical inflexibility of gas distribution systems. However, the regulators represent more than just the interests of the gas consumers because they also have the responsibility of ensuring the financial viability of the distributors and the pipelines. To the extent that local regulatory bodies are successful in representing interests in addition to those of the consumers alone, they tend to act as a buffer between buyer and seller in the marketplace and therefore to complicate the communication of timely signals between the parties.

Direct consumer response to gas price fluctuations would only seem to occur when customers 1) reduce gas consumption by some sort of conservation strategy or 2) switch to another energy source. In this regard, the consequences of actions available to industrial consumers often differ markedly from those of non-industrial customers. The reason is that many of the newer industrial boilers ard other gas-consuming devices can be fired by a variety of fuels, so that an industrial consumer can often switch back and forth between fuels according to price and convenience. Thus, to some extent, there is an avenue for a classic consumer response to prices in the industrial sector of the gas market. Other customers, however, are far less mobile. If they are to change energy sources, they must invest in totally new heating equipment. Naturally they are reluctant to make such investments and will suffer a certain amount of excess price over other energy sources before investing in new heating equipment to switch to a more economical energy source. In a sense, then, such customers are "captive", and if they are using gas they will continue to do so until the price of gas becomes high enough that they can recoup in a few years' time the cost of switching to a new energy source. When that happens, however, they are captive of another energy source and will not return to gas unless there is a significant price premium favoring its use. In other words, once the market response to excessively high gas prices is beginning to be clearly evident, a number of non-industrial customers may have vacated the market on a more-or-less permanent basis -- never to return until the price advantage is strongly in favor of investing in new heating equipment to use gas and discarding equipment employing alternative energy sources.

The mechanical inflexibility of natural gas transportation technology creates unusual market conditions and relationships that would seem to deserve explicit consideration in the process of making changes in the regulatory structure affecting pipelines and their operation. The rapidly escalating prices of alternative energy sources, and the continuing concerns about future natural gas supplies, would seem to make it difficult to predict how pipeline companies will react to major changes in regulation that might be implemented in the near future. However, the inflexibilities of the gas transportation system are a source of great stability in some respects, but of instability in other respects. Thus it would seem essential, in considering any changes in the regulation of the natural gas transmission pipelines, to seek to capitalize on the positive aspects of that inflexibility while avoiding the negative aspects.

CHAPTER VI

FEDERAL REGULATION OF NATURAL GAS PIPELINES*

The Industry

As indicated earlier, natural gas transmission can be considered as the "man in the middle". On the one hand are the gas producers and on the other are the distributors. The pipelines buy from one and sell to the other. As a consequence the lines run from the major producing areas to the major consuming areas.[1] In general this means in a northerly direction since approximately 85 percent of the gas is produced in the southcentral area (Texas, Louisiana, Oklahoma and Kansas), while more than 20 percent each is consumed in the Appalachian - New England and Great Lakes - Northern Plains regions. Of the remaining 60 percent, half is consumed in the Gulf Coastal states. The last 30 percent is used in the remainder of the U.S.

The major producing states are Louisiana (36 percent), Texas (35 percent), Oklahoma (9 percent), New Mexico (6 percent), and Kansas (4 percent). The major consuming states are Texas (19 percent), California (8 percent), Louisiana (8 percent), Illinois (7 percent) and Michigan (5 percent). A review of the flow pattern (table 1) indicates the heavy dependence of the consumer on the Gulf states. In all cases except for the Rocky Mountain and Pacific areas, the bulk of consumption is supplied from Texas, Louisiana and adjacent states. The

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* Prepared by Alvin Kaufman, Senior Specialist - Mineral and Regulatory Economics.

[1] U.S. Congress. Senate. Committees on Energy and Natural Resources, and Commerce, Science and Transportation. Committee Print, 95th Cong., 1st Sess. Washington, U.S. Govt. Print. Off., 1977. pp. 4-22.

TABLE 1

Natural Gas Sources and Consumption by Region, 1975

Consuming Region a/	Percent Consumption	Major Supply Region a/
New England	1.5	Gulf Coast (87%) b/
Appalachian	17.8	Gulf Coast (81%), Local (12%) c/
Southeast	6.9	Gulf Coast (88%), Local (6%)
Great Lakes	16.1	Gulf Coast (52%), Hugoton-Anadarko (28%)
Northern Plains	4.2	Hugoton-Anadarko (60%), Permian Basin (26%)
Midcontinent	8.5	Hugoton-Anadarko (70%)
Gulf Coast	29.5	Local (63%), Permian Basin (19%)
Rocky Mountain	2.8	Local (76%), Hugoton-Anadarko (17%)
Pacific Southwest	10.8	Local (49%), Rocky Mtn (21%), Imports (16%)
Pacific Northwest	1.5	Imports (89%)
Alaska	0.4	Local

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a/ See appendix ID for definition of regions.

b/ Gulf Coast includes South Louisiana and the Texas Gulf Coast (FPC supply areas 3 and 4).

c/ Local is defined as from within the region.

Source: U.S. Federal Power Commission. Bureau of Natural Gas. National Gas Flow Patterns 1975. February 1977. Washington, 1977. p. 9.

Rocky Mountain and Pacific Southwest regions are dependent primarily on local supplies. Only the Pacific Northwest has a heavy dependence on imports, primarily from Canada.

Of the total gas flow, approximately two thirds is subject to Federal regulation. In 1979 there were 89 interstate pipeline companies with revenues in excess of $1 million annually (Class A and B companies). These accounted for 99 percent of interstate sales. Among these are 32 companies that each carry more than 50 billion cubic feet of gas annually in combined sales for resale, transported or stored for a fee. These major companies account for 86 percent of the total class A and B sales, 95 percent of the sales for resale, and 63 percent of the industrial sales.2/

Among these major companies, the 10 largest are listed in table 2. The sales ranking for 1979 is not substantially different from that existing in 1970. In the latter year, Texas Gas Transmission Corp. would have ranked 10th, while Michigan-Wisconsin Pipeline Company would have ranked number 11. All of the top 5 in 1979 would have been in that group in 1970, albeit in a somewhat different order. El Paso was number 1 in both years. In the majority of cases, a major market is served by a single pipeline. Table 3 indicates some of the major areas and the lines providing service. This limit is the result of regulatory fiat rather than competitive conditions. Several lines serve a state, and in recent years, interties have been developed.

In terms of supply, however, there has been a good deal of change over the decade. El Paso, which was number 1 in 1970, is not in the top 10 in 1979. United Gas Pipeline Company and Texas Gas Transmission Corporation likewise

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2/ Unless otherwise indicated, data are derived from U.S. Department of Energy Information Administration. Statistics of Interstate Natural Gas Pipelines Companies 1979. DOE/EIA-0145(79), Washington, 1980. p. 263.

TABLE 2

Total Sales and Supplies, Ten Largest Pipeline Companies, 1979

Company	Volume of Sales		Supplies	
	Rank	% of Total a/	Rank	% of Total a/
El Paso Natural Gas Co.	1	7.6%	--	4.3%
Columbia Gas Transmission Co.	2	7.6	1	8.7
Tenneco, Inc.	3	7.4	5	6.3
Natural Gas Pipeline Co. of America	4	6.7	4	6.6
United Gas Pipeline Co.	5	6.2	--	2.6
Texas Eastern Transmission Corp.	6	5.9	3	7.2
Northern Natural Gas Co.	7	4.9	6	5.9
Michigan-Wisconsin Pipeline Co.	8	4.8	7	5.7
Transcontinental Gas Pipeline Corp.	9	4.7	10	4.9
Panhandle Eastern Pipeline Co.	10	4.5	8	5.9
Total	--	60.3%	--	57.2%

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a/ Percent of total sales or supplies for major companies.

Source: U.S. Department of Energy, Statistics of Interstate Natural Gas Pipeline Companies 1979, p. 45.

TABLE 3

Pipelines Serving Major Cities

Market	Pipelines
Boston	Teneco, Algonquin
Chicago	Natural Gas Pipeline (Mid-Con)
Detroit	Panhandle Eastern, Mich.-Wis.
Los Angeles	El Paso, PG&E (local)
New York	Transco
Washington	Columbia Gas

Source: Interstate Natural Gas Association of America dropped out. On the other hand, Southern Natural Gas Company ranked 9th in 1979 but was not in the top group in 1970. Consolidated Gas Supply Corporation rose from 8th in the latter year to 2nd in 1979. These last two companies, however, were not in the top 10 in terms of sales and so are not included in the table.

It will be noted that sales and supplies are rather evenly split among the 10. None of the companies has more than 7.6 percent of total major company sales, and none less than 4.5 percent. In the aggregate, in 1979 the 10 largest companies accounted for 60 percent of sales by major interstate pipelines.

In terms of supply, no company held more than 9 percent nor less than 2.6 percent. In the aggregate, the ten largest companies controlled 57 percent of gas supplies. In this regard, it should be noted that the largest reserves of gas are held by oil companies. The top five (Exxon, Texaco, ARCO, Standard-Indiana, Mobil) hold close to 30 percent of the total proved reserves in the U.S. There is some double counting since part of these reserves are under contract to the transmission companies and could be considered part of their supply.3/

Some nine pipelines are owned by producers such as Shell Oil Company (Blue Dolphin Pipe Line Company). In addition, three of the top ten are owned by companies having producing facilities or producing subsidiaries. These include Columbia Gas Transmission Corporation (Columbia Gas System Inc.), Michigan-Wisconsin Pipe Line Company (American Natural Gas Company), Natural Gas Pipeline Company of America (Peoples Gas Corporation). Aside from the

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3/ Hersh, Amy. Concentration Levels in the Production and Reserve Holdings of Crude Oil, Natural Gas, Coal and Uranium in the U.S. API Discussion Paper #004 R, February 14, 1977. p. 36.

above, four of the largest lines own producing facilities. These include El Paso, Panhandle Eastern, Texas Eastern, and Transco. It is apparent from the above discussion that most of the largest companies are connected to producers. In total, some seven pipelines are owned by producers, 25 are owned wholly or in part by corporations with other subsidiaries that produce natural gas or that own producing facilitites, twelve own producing subsidiaries, ten own production, and seven are involved in distribution.

In the material that follows, the data will relate to all class A and B companies in some cases, and only to the major companies in other instances. The latter will be specifically noted.

Current Situation

There are currently 265,105 miles of pipeline. Of this, 73 percent are for transmission, 25 percent for field lines, and 2 percent for storage lines. Transmission line diameter varies from less than 5 inches to over 30 inches. Close to one fourth of the transmission mileage is in pipe between 25.1 to 30 inches, with an additional one-third of the mileage ranging between 15.1 to 25 inches. Thus, the bulk of the mileage is in pipe between 15.1 to 30 inches in diameter. Some 30 percent of the mileage is ten inches or less in diameter.

The lines served 5.4 million customers, of whom 3000 are sales for resale customers, 3700 are main line industrial customers, and the remainder are ultimate customers. Throughput was 35.4 trillion cf of gas in 1979. Of this quantity, 42 percent was sold for resale, 16 percent was exchanged, 15 percent was delivered for others, 12 percent was delivered by others, 8 percent was sold to the ultimate customer, 4 percent was delivered to storage, 2 percent was used, and less than 1 percent was unaccounted for.

The major companies, as shown in table 4, followed the same relative pattern in 1979, but these companies exhibited an interesting trend over the decade. Sales for resale and other sales declined in importance, while exchange gas and deliveries by or for others increased. Gas produced and purchased also declined, while other receipts, including deliveries and exchanges, rose in importance. This shift occured in an effort to continue operating at as close to optimal capacity as possible during the recent gas shortage. Total gas deliveries bottomed out in 1975, while sales dropped through 1977. Despite the decline in sales in the latter year, deliveries were up 4 percent over 1975, sparked largely by deliveries by and for others. In 1979, total deliveries were 26.6 percent higher than 1975, and sales were 9.9 percent above the 1977 low.

It is apparent the pipelines have moved from a pure utility status to a modified form of common carrier status carrying large quantities of gas for others, as well as moving toward a tighter integration of the pipeline system.

These shifts have been reflected in expenditures for additions to plant. The restrictions on ultimate gas use, relatively low price, and lack of gas supplies resulted in a declining investment in pipeline expansion through the early part of the decade (table 5). With the subsequent upturn in sales and improved prices, these expenditures turned up. By 1979, additions were 42 percent over 1970. Considering that the cost of fixed nonresidential investment in the U.S. had increased by close to 90 percent over the same period, additions were still substantially below the 1970 level in real terms (i.e. discounting for inflation). Further, there was a major shift in how the money was invested during the decade. Additions to production plant rose from approximately 9 percent of the total in 1970 to close to 40 percent in 1979, while transmission additions dropped from 75 percent to 45 percent. It is apparent the companies

TABLE 4

Pipeline Deliveries and Receipts, Major Companies, 1970-1979

Items	1970	1975	1977	1979
Total Deliveries and Unaccounted for (Bcf)	24,982	24,730	25,689	31,279
		Percent		
Sold for resale	62.8	55.6	50.0	44.9
Exchange	8.7	14.6	16.1	18.0
Delivered for others	7.8	9.7	13.3	13.7
Delivered by others	5.7	6.7	8.9	13.0
Other Sales	6.5	3.9	3.4	3.3
Delivered to Storage	3.6	4.4	4.5	3.8
Used	3.5	3.0	2.6	2.3
Unaccounted for	0.3	0.3	0.4	0.3
Miscellaneous	1.1	1.8	0.8	0.7
Receipts				
Gas Produced	3.4	2.4	2.1	2.0
Gas Purchased	70.6	61.3	55.8	49.3
Other	26.0	36.3	42.1	48.7

Source: U.S. Department of Energy, Statistics of Interstate Natural Gas Pipeline Companies 1979, p. 37.

TABLE 5

Additions To Gas Plant, 1970 to 1979, Major Pipelines

Year	Plant In Service (Billion $'s)	Additions To Plant					
		Total (B $'s)	Index (1970=100)	Production	Storage	Transmission	Other
				(Percent of Total)			
1970	$17.6	$1.12	100	8.8%	9.9%	74.6	6.7
1971	18.4	0.87	78	13.2	8.9	73.1	4.8
1972	19.4	0.83	74	21.3	10.8	58.1	9.8
1973	20.1	0.77	69	23.6	7.8	62.1	6.5
1974	20.6	0.67	60	30.7	9.8	51.6	7.9
1975	21.6	0.88	79	23.9	13.0	55.9	7.2
1976	22.1	0.59	53	31.7	11.7	46.1	10.5
1977	23.1	1.09	97	32.0	12.7	47.8	7.5
1978	24.6	1.57	140	30.1	13.8	49.2	6.9
1979	26.1	1.59	142	39.9	7.9	44.9	7.3

Source: U.S. Department of Energy, Statistics of Interstate Natural Gas Pipeline Companies 1979, p. 35.

had shifted from expansion of the system to developing additional supplies to serve existing customers.

This shift is reflected in operation and maintenance expenses for the major companies as well. Production expenses rose from 59 percent of operating revenues in 1970 to 74 percent in 1979. This represented an increase from 22.2¢/Mcf to $1.44 in the latter year. Transmission and storage charges declined as a proportion of operating expenses from 8.4 percent in 1970 to 7.4 percent in 1979. This decline occurred despite an increase in these costs from 3.2¢/Mcf in 1970 to 14.5¢ in 1979.

Despite the change in expenditures for additions to plant, all classes of gas reserves are down in 1979 compared with 1970, gas in storage is one third less, and transmission pipeline mileage is up 13 percent. The drop in reserves, coupled to the rise in sales, results in a decline in the sales-life index from 14.79 in 1970 to 8.36 in 1979. It would thus appear that the shift in expenditures is an effort at survival, or at least an effort to slow down the depletion of gas reservoirs.

The problems and trends indicated above are reflected in the earnings of the pipelines. The lines' net income as a percent of stockholders equity has stayed consistently under that for manufacturing (table 6). It has remained relatively constant over the period, while manufacturing profits have increased substantially. Net income as a proportion of total assets, on the other hand, has increased by a factor of 1.75 over the decade, approximately the same as manufacturing. This disparity between the two net income series may be the result of the three-fold rise in net income over the 1970-79 period, compared with a doubling of total assets, while long-term debt rose by close to 4.5 times the 1970 level. In any case, it is apparent relative earnings by the pipelines are less than in manufacturing. Earnings appear to be lower than

TABLE 6

Comparison of Relative Earnings, 1970-1979, Major Pipelines

Year	Yield on Utility Bonds a/	Manufacturers Profits b/ vs Stockholders Equity	Pipeline Oper. Income vs Investment	Pipeline Net Income vs	
				Total Assets	Stockholders Equity c/
1970	8.78%	9.3%	7.3%	3.9%	7.9%
1971	8.13	9.7	8.1	4.4	8.8
1972	7.74	10.6	8.7	4.6	9.2
1973	7.83	12.8	9.1	5.0	8.9
1974	9.27	14.9	10.0	5.8	9.8
1975	9.88	11.6	10.3	5.7	9.5
1976	9.17	13.9	11.7	6.0	9.7
1977	8.58	14.2	11.4	6.2	9.2
1978	9.22	15.0	11.1	6.1	9.0
1979	10.39	16.4	11.3	6.6	9.2

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a/ Moody's, 40 Bonds.

b/ Profits after tax.

c/ Total assets less long-term debt.

Sources: U.S. Bureau of Census. Statistical Abstract of the U.S. 1980. Washington, 1980. p. 545; U.S. Congress. House. Economic Report of the President. House Document No. 97-3, 97th Cong., 1st Sess. Washington, U.S. Govt. Print. Off., Jan. 1981. p. 329; U.S. Department of Energy, Statistics of Interstate Natural Gas Pipeline Companies 1979, pp. 27-29.

the cost of debt to the utility as well. Pipeline operating income as a percent of investment, however, is above the yield on utility bonds, but net income (net after debt service and taxes) as a percent of either assets or equity is less. This disparity may indicate the impact of debt service and taxes. It should be noted that operating income and bond yield are more comparable measures because both are before debt and taxes.

Pipelines and Natural Monopoly

The earlier discussion indicates that the pipelines have managed to surmount a variety of problems and still remain relatively healthy. The important question, however, is whether circumstances have changed sufficiently to warrant operation without regulation. This, in turn, hinges on whether the pipelines are natural monopolies. A natural monopoly, as discussed earlier, has a number of characteristics. Chief among these are: 1. decreasing long term costs; 2. high entry investment; and 3. a technology that limits the number of potential operators.

Insofar as the last point is concerned this has been discussed in detail in an earlier section. Suffice it to say that the technology in terms of equipment (i.e. pipe, pumps, compressors, etc.) is not unique. In that sense, a natural gas pipeline does not meet the technologic criteria for a natural monopoly. The line once laid, however, can not easily be moved to serve another area. This lack of flexibility and mobility suggests that the pipelines do meet the criteria. The pipeline, once laid, is unique becoming both the "jailor" and "prisoner" of the producer and the distributor.

We can now turn to a discussion of entry costs.

Investment. The gas pipeline industry had total assets of $44.4 billion in 1979, and gas plant in service valued at $31.8 billion. Fixed nonresidential business capital for all U.S. industries comprised $364 billion in that year. Thus, the pipeline industry is approximately 10 percent of the total, and as such can be considered a relatively minor industry in terms of finances.

Despite this, capital invested per employee ($615,500) is among the highest for any industrial group in the U.S.[4] To an extent this reflects the fact that pipelines are not labor intensive and most of the equipment tends to be automatic. Looked at another way, close to $230,000 is invested for every mile of transmission on an original cost basis. The actual cost of laying a mile of pipe would be considerably higher since it would reflect current prices while the earlier figure is weighted downward by the costs incurred years ago. In 1979, the cost of adding 2744 miles of transmission was $1.1 billion or $403,000 per mile. To this would have to be added the cost of necessary storage, processing facilities, gas production, gathering lines, etc. The total cost would then be close to $600,000/mile.

From the above, it is apparent that a substantial investment is required to enter the natural gas transmission business. In 1979, the average class A and B pipeline had assets of close to $500 million, with a range between $800,000 and $7.2 billion. The bulk of the companies (47 percent) have assets of less than $100 million, with 12 percent exceeding $1 billion. The remaining 41 percent are rather evenly distributed throughout the $100 million to $1 billion range. The modal average asset size for the 89 companies is $52.5 million. The mode is the value that appears most frequently in the distribution. This, however, includes a number of relatively local pipelines. If one looks solely at the major lines, one-third have assets in excess of $1 billion, 10 percent are in the $900 million to $1 billion range, 10 percent have assets of less

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4/ U.S. Bureau of the Census, Statistical Abstract of the United States: 1980, p. 561.

than $100 million, and 16 percent are in the $200 to $300 million class. A high entry investment is required to enter the gas transmission business.

Costs - It is generally held that a natural monopoly should exhibit declining long-term unit costs. This occurs because the relatively high-fixed costs mean that higher output will result in lower unit costs. The optimal use of plant becomes possible if the monopoly can enjoy an unrestricted access to its territory. That is, since it cannot sell throughout the Nation to anyone willing to buy, but is restricted to marketing in those areas, for example, where the pipeline goes, competition in the accessible markets would reduce the economic efficiency of the operation. It is, therefore, desirable to permit monopoly status and enhance the efficiency of operation, thus achieving reduced costs. In the modern world, however, this monopoly position can be threatened not only by the sale of gas by competitors but also by the sale of substitute energy sources such as electricity or distillate oil.

In any case, in an effort to measure the cost trends in the industry we have constructed a series of indices using 1972 as the base year (table 7). In doing so all dollar figures have been adjusted to eliminate the impact of inflation, and are thus in real terms.

It will be noted that deliveries have followed an erratic path over the decade, but total expenses have exhibited a straight upward trend. By 1979 these expenses were 2 1/2 times the 1970 level in real terms. Pipeline costs have also increased, but not at the same rate as total expenses. Transmission expenses, on the other hand, have tracked deliveries rather closely, indicating a strong relationship between these costs and deliveries.

On a unit cost basis, however, total expenses indicate an almost steadily rising trend. Unit cost in our case has been taken as dollars per Mcf-mile. Thus the unit reflects both the throughput of the line and the size of the

TABLE 7

Index of Pipeline Expenses, 1970-1979, Real Dollars (1972=100)

Year	Index of Deliveries	Index of Expenses (1972 Dollars)					
		Total a/	Pipeline b/	Transmission c/	Cost Per Mcf-Mile		
					Total	Pipeline	Tranmission
1970	94.4	91.5	81.7	94.3	106.3	95.1	109.9
1971	93.7	94.1	92.5	97.4	108.6	107.2	113.0
1972	100.0	100.0	100.0	100.0	100.0	100.0	100.0
1973	100.2	101.2	102.7	100.8	100.0	101.8	100.0
1974	96.8	108.0	102.7	95.6	110.9	105.6	98.5
1975	93.4	119.8	107.5	92.1	126.4	113.6	97.3
1976	94.7	136.6	118.1	95.7	144.3	124.9	101.2
1977	97.1	166.9	120.7	102.7	170.1	123.4	105.1
1978	104.7	180.4	123.2	106.2	169.5	116.0	100.0
1979	118.2	226.8	132.2	121.0	186.6	109.0	99.7

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a/ Operation and Maintenance Expense, depreciation, taxes, long term debt interest.

b/ Total expenses less production costs (O & M and capital).

c/ Transmission O & M expenses plus an allowance for transmission capital costs.

Source: Based on data in Statistics of Interstate Natural Gas Pipelines - 1979, DOE/EIA-0145(79), p. 29, 32, 35, 37, 38 and Economic Report of the President 1981, p. 236.

system. If deliveries alone were used as the unit, the trend of unit cost is virtually the same as obtained with the hybrid unit.

In any case, total cost per Mcf-mile exhibited an inverse relationship to deliveries through 1975. That is, as deliveries declined, cost per unit increased. After 1975, however, cost per unit tended to rise even as deliveries rose. This is probably the result of higher gas costs.

The average price of natural gas to gas distribution companies has increased 417 percent from 1970-1979. As a consequence the producer's share of the average city-gate gas price rose to 70 percent in 1979 compared with 49 percent in 1970. It is anticipated by AGA that the producer's share will escalate to 90 percent in 1985 and 91 percent in 1990.5/ This escalation indicates that pipelines are no longer able to control a major cost element. Inasmuch as this major element can be considered separately, a better measure of cost may be pipeline costs (storage, transmission, general) only.

A review of these costs indicates a steady rise throughout the decade. On an Mcf-mile basis, however, these costs rise from 1972 to 1976 and then decline steadily. There is obviously a relationship between these costs and deliveries. Apparently once the problems of obtaining sufficient gas were solved and deliveries started to increase again, costs began to decline.

Transmission unit costs have tended to follow a more erratic path. These costs exhibited an inverse relationship to deliveries through 1972, a positive relationship between 1973 and 1977, and inversely again in 1978 and 1979. The overall trend appears to be downward.

From the foregoing, it appears that total costs are no longer benefiting sufficiently from economies of scale to cause a decline, while pipeline and

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5/ Evaluation of the Increasing Percentage of Commodity Costs in the Average Retail Price of Gas. Gas Energy Review. AGA, August 1981. pp. 7-10.

transmission costs alone may be doing so. It can be concluded that natural gas production costs are now biasing total costs upward. Once this effect is excluded, pipeline costs tend to follow an inverse trend compared with deliveries, and appear to exhibit the effect of economies of scale.

A Natural Monopoly - The preceding discussion has attempted to assess the natural monopoly characteristics of the gas transmission industry in terms of technology, capital, and costs. In terms of technology there is nothing unique about a gas pipeline, but it does lack flexibility and mobility. As a result, once it is laid it is not practical to pick it up and move it. Further, the construction of a competing line would make it difficult to achieve economies of scale.

In terms of capital, we have demonstrated the industry has a relatively high requirement per employee compared with other industries. The cost per mile is less than the average $800,000 cost to build all kinds of highways, but still is substantial. Further, while the bulk of the lines have assets less than $100 million, and the modal average assets are $53 million, the major companies generally have assets in excess of $900 million. It would thus appear that a high entry investment is required.

Unit costs, on the other hand, exhibit conflicting trends depending on what one includes in costs. Taken separately, pipeline costs (total minus production) exhibit an inverse relationship to deliveries. These now appear to be declining as deliveries rise. These costs have not been examined over the long-term, and the past decade, with its supply problems and regulatory actions designed to limit demand, may not be typical. Despite these difficulties the data do appear to indicate that some economies of scale are available if only those costs connected with the transportation of gas are considered. These include transmission, storage, and overhead costs.

The above suggests that in general the pipelines meet the criteria for the establishment of a natural monopoly, and thus would benefit from being regulated in some way.

Pipeline Regulation

Pipeline regulation, as now practised, is based on the public utility concept. The line is charged with the responsibility of obtaining an assured supply of gas for a 20 year period, moving that gas to storage or to the customer, and finally selling it to the distributor or industrial consumer. Throughout this process, the pipeline acts for its own account and not as an agent or broker. It owns most of the gas pushed through the line, although in recent years there has been an increase in gas carried by or for others, as discussed earlier.

In any case, with impending price deregulation at the wellhead, a situation analogous to that in the early '70s could develop. That is, distributors may be unable to sell gas. The difference between the earlier problems and the new situation is that the impediment may be price rather than a shortage of gas.

A recent study of 14 pipelines purchasing 70 percent of the domestic gas going into the interstate market indicates an average gas cost of $1.95 per Mcf. Of this gas, however, one-third is in the higher priced NGPA categories with an average price of $3.23. The overall average cost of gas will increase due to increased volumes of higher priced gas, and because of shifting from lower priced categories to higher priced subcategories in the same group.6/

6/ Edmund R. Dupont and Associates. Preliminary Assessment of Gas Rate Changes Under NGPA. Gas Energy Review. Arlington, Virginia A.G.A., September 1981. pp. 2-5.

As shown in table 8, new gas constitutes 15 percent of gas volume, but 22 percent of total value due to its higher unit value compared with old gas. Under current law new gas will be decontrolled on January 1, 1985, if it is gas from wells deeper than 5000 feet and was not dedicated to interstate commerce on April 20, 1977, or was intrastate gas as of that date if the contract price is greater than $1 per million Btu on December 31, 1984. Gas from wells less than 5000 feet deep and not dedicated to interstate commerce on April 20, 1977, will be deregulated on July 1, 1987.7/

It will be noted in the table that those gas sources that will be decontrolled or are currently exempt from regulation sell at average prices considerably above old gas. As the latter sources are depleted, gas will be derived from a larger proportion of the newer and more expensive classifications. Thus, the average price for all gas will rise in any case. This increase may be even more substantial than anticipated in that gas from high cost sources which currently has an average price of $6.03 per Mcf, is currently being contracted for by the pipelines at higher prices. For example, three recent contracts for gas from wells over 15,000 feet deep have been negotiated by Transco, Tenneco, and Columbia Gas Transmission Co. at prices ranging between $8.72 and $10.11 per Mcf ($8.59 to $9.96/million Btu).8/

This situation is compounded by the provisions of existing contracts.

Contract Provisions and Regulation. As a consequence of the high fixed cost nature of the business, pipelines usually assure their supplies and markets through relatively long-term contracts. Contracts for "old gas" must be filed

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7/ 92 Stat 3369-3370.

8/ Newsletter, Oil and Gas Journal, November 2, 1981.

TABLE 8

Share of Gas by NGPA Classification

Gas Classification	NGPA Section	Share of Total Gas (%)	Average Price Per Mcf	Weighted Average Share of Cost (%)
New Gas	102	14.7	$2.92	22.0
New Onshore Wells	103	10.1	2.71	14.0
Old Gas	104/106	69.6	1.39[a]	49.6
High Cost Sources	107	3.8	6.03	11.8
Stripper	108	0.8	3.43	1.4
Other	109	1.0	2.27	1.2
Total		100.0	$1.95	100.0

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[a] Section 104 gas appears to be 50 percent pre 1973 supplies at 50-75¢ per Mcf and 50 percent post 1973 gas at $2.00.

Source: Edmond R. DuPont and Associates. Preliminary Assessment of Gas Rate Changes Under NGPA, A.G.A., p. 4.

with the FERC, and usually are subject to the approval of that regulatory body. Contracts for gas not subject to regulation need not be filed with FERC.

Over the years the contracts between the pipeline and producers on the one hand and the pipeline and distributors on the other have acquired a number of accretions designed to protect the financial viability of both the producer and the pipeline. Chief among these are the purchased gas adjustment clause, take or pay clauses, minimum bill requirements, and price escalator clauses.

The latter is a clause that ties the wellhead price of gas, once deregulated, to some indicator, such as the price of No. 2 fuel oil. Such an arrangement benefits the producer by raising his price as the index rises. For example, as the OPEC cartel increases oil prices, gas prices will rise if indexed to fuel oil. A price established in such a manner has little to do with the relative costs of gas production and thus may give the consumer the wrong signal. The result can be a misallocation of economic resources. Further, such a price setting mechanism tends to overlook the condition of the market. The price escalator clause is not equitable, but does assure reliable and adequate supplies of gas as well as the financial viability of the producer.

Escalators, together with the take or pay clause, insulate the producer from the vagaries of the market place, and make it difficult for the pipeline to respond to changes in the market. The take or pay clause requires the pipeline to take certain quantities of gas, often 75-90 percent of the contracted quantity. In the event the gas is not taken the line is still obligated to pay for the minimum quantity. The result is the assurance of the producer's revenues, but presents the possibility of uneconomic pipeline expansion. That is, the line may expand their market in order to assure it can take the gas since it may be better to get some revenue from the sale of take or pay gas rather than none.

The pipeline is, however, also insulated from the problems created at the producer end by the purchased gas adjustment clause (PGA) and the minimum - bill provision. Under the PGA, the escalated wellhead price would be automatically passed through to the customer (distributor or large industrial user). This is reinforced by the requirement that the customer pay at least an amount equal to a set percent of its gas entitlement regardless of the gas actually taken. The result of these provisions is to assure the recovery of the pipelines' gas and fixed costs, but these insulate both the pipeline and producer from marketing problems to a considerable extent, and weaken the pipelines' incentive to negotiate with producers'. In addition, the minimum bill requirement ties the distributor to the pipeline reducing its ability to take advantage of offers from other sources. This system is mitigated to an extent by the market-knock-out provision. Some contracts reduce the distributor's minimum bill or unit price if market conditions dictate. Such clauses, while useful in exposing the pipeline to the play of the market, could cause serious financial difficulty unless carried through to the producer as well.

The foregoing discussion indicates that a system has been developed that assures that most of the regulatory goals will be met, with particular emphasis on the financial stability of the pipeline and the producer. As noted above, however, if the producer price is deregulated, these clauses may then serve to insulate both the pipeline and producer from the market, while leaving the distributor exposed. If the state regulators failed to approve the price paid the pipeline for pass through to the ultimate customer, the financial condition of the distributor would be threatened. On the other hand, if the price were approved, the distributor might face consumer resistance and subsequent loss of market. These reactions would not be felt by the pipeline for some time, and by the producer for an even longer time. This then tends to insulate the pipeline from the consequences of its actions, and does so to an even greater extent for the producer. The question thus raised is how to reduce this insulation while maintaining the gas system. Several studies of the importance of these clauses have been completed. At this point it may be useful to review the results of these.

The Impact of Contract Provisions. In an effort to determine what these provisions are, the A.G.A. recently had a study made of what is believed to be a statistically valid sample of the 20,000 contracts on file at FERC.9/ In this regard it should be noted that pipelines are not required to file contracts for new gas, high cost gas, etc. As a consequence, most of the contracts on file at FERC deal with old gas or rollovers of existing contracts (sections 104/106). Thus, the filed contracts deal with 70 percent of the gas by quantity and 50 percent by value. It is apparent that the data presented below leave out a substantial portion of the contracts. It may be, however, that those contracts not on file are more stringent in the sense that escalation may be more prevalent and buyer escape clauses less so.

In any case, it can be inferred, based on the sample data, that between 85.4 and 92.6 percent (90 percent confidence level) of the contracts authorize the use of the highest allowed price under regulation. Of the pre-1973 contracts, 25 percent have been amended to authorize the highest regulatory price, and 20 percent were amended to add an indefinite price escalator. Of the contracts negotiated prior to 1973, 75 percent contain this type of clause,

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9/ Decision Analysis Corp. Analysis of Natural Gas Producer/Interstate Pipeline Contracts. Gas Energy Review. Arlington, Virginia A.G.A., September 1981. pp. 5-9. Somewhat more comprehensive data were released in: Energy Information Administration. Natural Gas Pipeline/Producer Contracts, A Preliminary Analysis. U.S. Department of Energy. December 1981, p. 37. While the numbers are different, the substance and conclusions are the same as discussed above.

while 99 percent of the contracts since April 20, 1977 have such a price setting mechanism.

The indefinite price escalator clause usually provides that, in the event of deregulation, the price paid by the pipeline will be pegged at the Btu equivalent of various oils, to an average of the highest contract prices in an area, or to the highest price paid by the buyer for gas. In some instances, the clause may provide for the highest price obtained using all of the various methods. Redetermination of the price is often allowed at intervals of 1 to 5 years, usually at the request of the producer.

The study estimates that between 61.6 and 72.4 percent of contracts on file at FERC contain an indefinite price escalator clause. Of these, 8 percent are pegged to the price of #2 oil, 3 percent to #6 oil or crude, and 83 percent to the average of the 1 to 3 highest contract prices for the same area (most favored nation clause). Thus, any new contract providing a high gas price will automatically raise the price of all other gas produced in an area. Only 7 percent of the contracts have a limit on the price escalation possible upon deregulation, and 13 percent provide for negotiation on the basis of the fair market value of the gas, while 4.8 percent provid for a minimum price. It is thus apparent that natural gas prices may escalate dramatically after deregulation, keeping in mind that the oil equivalent price would be in the $5 to $6 range.

This escalation, in normal circumstances, would be tempered by the reaction of the market to the price increases. In this case, however, only 22 percent of the contracts having indefinite price escalators give the buyer recourse, and only 10 percent allowed recourse on marketability grounds, 13 percent permitted a lower price if FERC disallowed the redetermined price and 4.5 percent gave the pipeline the right of first refusal on any price offered by another buyer and found acceptable by the seller when the escape clause has been implemented. From the above, it is apparent the pipeline, in most cases, has no recourse but to accept the gas at the new contract price even if that price creates market problems. It should be noted that the low percentage of market-out clauses may not apply to the newer contracts not subject to FERC jurisdiction. These may contain such clauses on a more prevalent basis.

Under the current system, however, the latter is of minimal interest to the line in the short run. That is, most pipelines have a purchased gas adjustment clause as a part of their tariff. This permits them to pass the increased gas costs through to the distributor or industrial user with minimal delay. Thus, in the short-run it is the distributor who will bear the brunt of the market reaction to higher prices since the minimum bill clause will make it difficult to reduce his take, even though he may suffer a reduction in demand.

Over the longer term, however, the plight of the distributor is of considerable interest to the pipeline since economies of scale can only be had at higher operating rates. Renegotiation of prices, quality of service, minimum take, etc., however, simply shifts part of the burden from the distributor to the line. The entity at the start of the chain, the producer, would still be insulated from the consequences of higher prices by take or pay clauses.

The regulatory problem thus appears to be a question of how to avoid having the regulatory system serve as a market insulator for the producer. If this were to occur, the producer could adjust his output and price, within contract limits, to maximize his revenues, leaving it to the pipeline and its customers to cope with the market reaction as best they could. In the event of partial deregulation, as provided by current law, it is likely that because of the average pricing (rolled-in) used in the industry the initial impacts after deregulation would be relatively minor, but would become more severe with time.

Eventually, of course, the producers would be forced to adjust prices in order to maintain a viable downstream gas industry. If all categories of gas are deregulated, the result could be a sharp jump in price. Much of this trauma could be avoided if FERC simply disallowed from pipeline tariffs those producer rates that appeared exorbitant. This puts a substantial burden on the regulatory agency, introduces an element of uncertainty into the pipeline business with attendant financial costs, produces an inconsistent result and is a defacto return to wellhead regulation. That is, decisions as to what may be allowable and what not may vary widely from case to case. Further, this action puts the full risk on the pipeline since only a small number of contracts permit recourse in such a case. The problem here is not with the regulatory system per se, but with the content of the contracts. The result must be an effort to remove the producer's market insulation while assuring the ultimate customer adequate and reliable service. For example, one study indicates that gas priced at parity with oil would result in a 24 percent drop in demand in 1990 and 33 percent in 2000 from expectations at EIA midrange forecast prices.10/ Thus, the high initial prices resulting from the workings of the contracts will eventually have to be mitigated in order to keep demand near production capacity.

It is not the purpose of this paper to project gas prices, but it may be of interest that Merrill Lynch projects an initial price after decontrol of $6-7/Mcf, falling back gradually to $4.70-$5.10/Mcf.11/ This would imply a decline in demand by 1990 of approximately one-fourth the anticipated level.

10/ Sant, Roger, Steven C. Carhart, with D.W. Bakke, and S.S. Mulherkar. Eight Great Energy Myths - The Least-Cost Energy Strategy, 1978-2000. The Energy Productivity Center, Mellon Institute, Arlington, Va., Energy Productivity Report No. 4, p. 40.

11/ Merrill Lynch Natural Gas Monthly, August 1981, p. 7.

A recent study has attempted to measure the impact of the contract price escalator clauses on utility sales and on average price. The A.G.A. has estimated that if no escalators were triggered the average retail gas price under decontrol, in real terms, would rise 62 percent by 1990 (table 9). If the escalators are triggered in 1985 for decontrolled gas, as would occur under current law and contract provisions, but renegotiated downward over the 1985-88 period, prices would rise 77.7 percent by 1985 but decline by 9 percent by 1990. The overall rise between 1981 and 1990 would be 62.5 percent. On the other hand, if price controls on all gas were phased-out by 1985, prices would more than double by that year and then decline for an overall increase in the 1981-90 period of 66.5 percent. Thus, while there would be varying increases in the 1981-85 period, the overall rise in the 1981-90 period would be relatively close in all cases as market prices worked their will.

Utility sales would follow an inverse pattern in the sense that the absence of the triggers would result in a 7.4 percent rise in the 1981-90 period. In the other cases sales would drop by 1985 by 3.1 percent and 14.2 percent respectively, and show modest increases of 4.9 percent and 1 percent over the full decade.

In the event the escalators were not phased out, prices would more than double by 1990 while sales declined throughout the decade. By 1990 the latter would be 13.5 percent less than in 1981.

In any case it is apparent from the foregoing that under the status quo insofar as pipeline regulation is concerned, deregulation at the wellhead will result in higher retail prices than currently exist. Under the more plausible deregulation scenarios posed by AGA, total sales will be higher in 1990 than at present. The modest impacts are in large measure the result of the mitigating effect of rolled-in pricing. That is, the consumer feels less pain in 1985

TABLE 9

Comparison of Gas Utility Sales and Prices Under Alternative Decontrol Plans

Case and Year	Gas Utility Sales (Q Btu)	Average Retail Price a/	Average Wellhead Price a/
1981	16.2	$ 3.76	$ 2.25
Case I b/			
1985	15.7	6.68	5.56
1990	17.0	6.11	4.61
Case II c/			
1985	17.0	5.36	3.94
1990	17.4	6.09	4.63
Case III d/			
1985	15.7	6.68	5.56
1990	14.0	8.04	6.56
Case IV e/			
1985	13.9	8.31	6.93
1990	16.3	6.26	4.71

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a/ Constant 1981 $'s per million Btu.

b/ Central Case - Indefinite price escalators triggered in 1985 for decontrolled (new) gas. These are phased-out thru renegotiation over the 1985-88 period.

c/ Optimistic Case - No price escalators triggered.

d/ Pessimistic Case - Price escalators triggered for decontrolled gas in 1985. Wellhead gas prices goes to 110 percent of distillate oil price. Escalators are not phased out.

e/ Three Year Phaseout - All wellhead price controls (old and new gas) are phased out between January 1, 1982 and January 1, 1985. No controls on wellhead price remain after 1985.

Source: A.G.A. Consumer Impact of Indefinite Gas Price Escalator Clauses Under Alternative Decontrol Plans. November 6, 1981. p. 28. The reader is cautioned that the AGA has a position on the question of wellhead deregulation.

when new gas is decontrolled but old gas is not, and gas at the citygate is priced as a weighted average of new and old. In the case where all gas is deregulated, retail price jumps in 1985 and then falls back as market forces operate.

Essentially, then, the model indicates that the producer gets the market signal sooner or later. The key is to devise a regulatory system that allows the signal to flow back sooner rather than later.

CHAPTER VII

LEGISLATIVE CONSIDERATIONS

Options for the Future*

The purpose of this study has been to examine, in some detail, the organization, operation and regulation of the natural gas industry. In doing so, technologic, economic, and legal issues have been identified that might be raised as a consequence of the decontrol of Federal wellhead pricing regulation. Of particular concern is the general question of whether decontrol at the wellhead raises significant issues with regard to other aspects of industry operation and regulation.

It seems clear that Federal wellhead price control has become the focal point around which Federal and state regulation of the other aspects of the industry revolves. Wellhead decontrol raises fundamental questions about the structure, operation and regulation of the industry. The issues thus raised go well beyond the immediate one of price effects on consumers and production incentives for industry.

While important policy options may exist to deal with the perceived effects of wellhead decontrol, only a fundamental discussion of these in relation to a specific legislative option can provide the thorough explication of relative merits that is needed for the important Congressional decisions which may have to be made.

In this regard, it may be appropriate to summarize the various items that have been identified as potential issues upon whose resolution the success of Federal wellhead decontrol may depend. These issues can be defined as:

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* Prepared by the Study Team (Kaufman, Crane, Nelson, and Poling).

1. Resolution of the producer-pipeline contract dilemma;
2. The legal effect of vacating wellhead regulation on possible expansion of state regulation of production and distribution; and,
3. The proper form and content of any continued Federal regulation of interstate pipelines.

The legal effects are discussed in detail in both the legal issues (chapter 4) and the state regulation section (Book II). That discussion will not be repeated here.

The Contract Issue. The contract issue has also been extensively discussed in Chapter 6. Suffice it to say that W.W. Schroeder has noted that contract provisions threaten to push gas prices above long-run market clearing levels, and that this poses the most serious obstacle to wellhead deregulation.[1] As a consequence, Schroeder points out that several proposals to modify or accelerate the NGPA decontrol timetable have been made. Other options include downward renegotiation between producers and pipelines of decontrolled gas prices in return for upward renegotiation of old gas prices in 1985. Schroeder maintains, however, that this option produces no net gain for producers. Therefore, early decontrol, coupled to renegotiation, is the price to be paid to cure the contract problem. Higher prices now could provide sufficient compensation for reduced decontrolled gas prices later. Alternatively, price escalators could be modified by legislation. There is, however, no solid coalition in favor of modification or more rapid decontrol. He maintains that the market transition problem resulting from decontrol is manageable, but that decontrol may be seriously jeopardized by the contract transition problem.

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[1] Schroeder, Walter W. The Outlook for Natural Gas Prices As Decontrol Approaches. Oil and Gas Journal, November 30, 1981. pp. 92-98.

Regulatory Options. Turning now to a discussion of the form and content of pipeline regulation, as noted earlier, some kind of regime is required. In this regard, MacAvoy and Noll have noted that gas prices are dependent on pipeline control of the market.2/ Such control is not likely because there is either no joint pricesetting mechanism, or there are too many firms to permit enforcement of decisions. Further, market allocation can not be used because of interfuel competition. Price levels are further dependent on distance to market and gas flow volumes. They conclude the major constraints on pipeline price control are: FERC; other sources of supply and supply control mechanisms; and cost condition constraints.

Thus, from a price viewpoint, the form of regulation probably makes little difference since the constraints remain. There are, however, several other issues that should be considered. These are discussed below.

Alternatively, the entire regulatory regime could be changed. In the event the relationship between the various segments of the gas industry were changed, questions arise as to how low load factor customers would be treated, what would happen to the obligation to serve, and will transportation prices be higher than under the current system?

Low Load Factor Customers. It is possible that customers with low load factor (that is, a big gap between peak and base load) might be unduly discriminated against. Sellers might demand penalties for seasonal load variations, requiring "take or pay" or large storage facilities. The latter could require a great deal of capital, which would be very hard to raise by small individual distributors. It is possible that the diversity of types of customers served

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2/ MacAvoy, Paul W. and Roger Noll. Relative Prices on Regulated Transactions of the Natural Gas Pipelines. The Bell Journal of Economics and Management Science, Spring 1973, pp. 212-234.

by any major interstate pipeline serves to some extent as a load leveler -- certainly this is true where there is any appreciable industrial use -- thereby obviating the need for storage. The producers and/or pipelines, however, if unregulated with regard to service maintenance and price, could place severe demands on distributors to maintain level consumption, or pay a substantial price. They might shift the storage burden to the distributors and away from the pipeline, so as to make the operation more "efficient" -- i.e., so that all customers would tend to have a demand curve that is like industry's: relatively level. At present the costs of storage are shared over a wide variety of demands and uses.

The Obligation to Serve. At present, the pipeline has an obligation to assure future supply, and to serve all comers. Under some other system, such as common carrier, the question arises of who would take over this obligation to ensure future supply? As things now stand, the State and local regulators have some degree of influence on the pipelines because of the obligation to provide service, but if distributors are "on their own" in dealing with producers, there is little that local regulators can do to help distributors hold down prices.

Transportation Prices. The creation of a new regulatory entity may result in higher financing charges due to greater perceived risk. For example, under a common carrier regime, the pipeline will be entirely dependent on its transportation revenues. It will no longer have access to the profits from production, and will no longer have control over gas sources. Thus, the line is more "exposed", in a financial sense, than in the past. This then raises the question of whether charges for transportation will be substantially higher than at present, and if financing will be available to the pipeline at an appropriate cost.

Regulatory Concepts*

The contract situation outlined above is essentially a symptom of the problems inherent in the current system. Based on our earlier discussions, what is required is a regulatory arrangement that assures economies of scale, encourages competition where feasible, and takes account of the need for sufficient revenues to cover the high-fixed costs inherent in pipeline operation. In addition, such a system must be evolutionary rather than revolutionary in order to avoid creating chaos due to the large number of long-term contracts currently in existence.

In the search for such an optimal system we can start by considering the broad concepts first. That is, should the pipelines be unregulated or regulated; if regulated should the lines be considered as a utility or as a common carrier? Once the operating concept has been determined, the appropriate options can be indicated. Our discussion will relate each concept to the goals of regulation.

Economic regulation is generally aimed at meeting a number of goals. Chief among these are the provision of adequate and reliable service by the regulated, achievement of economic efficiency, equity between all of the involved parties, and the assurance of the financial stability of the utility. The relative priority accorded each of these is a value judgment made by each regulatory body. Thus, to one set of FERC commissioners equity may be of greater importance than economic efficiency, while to the next set the reverse may be true. In any case, while some goals may be of greater relative importance at a point in time, these are all intertwined so all must be considered. For example, adequate and reliable service implies financial stability.

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* Prepared by Alvin Kaufman, Senior Specialist - Mineral and Regulatory Economics.

To Regulate or Not to Regulate. Unregulated pipelines, in theory, should be responsive to the market in establishing prices and investment patterns. As a result, the consumer would receive the "correct" price signal and the allocation of economic resources to gas transmission would be optimal.

In reality, since the pipelines appear to have the characteristics of a natural monopoly, the absence of regulation might encourage destructive competition in the short run. New entrants would enter the business, reduce prices in order to gain a foothold, and eventually go bankrupt. This would occur because of the inflexibility noted earlier. As a result, the older lines would have to compete to retain their markets, but this would be restricted to those areas where existing contracts were about to expire. Since existing lines would have portions of the market locked-up, and would have lower costs, these would probably survive. Lower costs occur because the older lines' capital is sunk and it need only recoup its Operating and Maintenance (O & M) costs plus debt service to stay solvent.

In any case, the result of deregulating the pipelines might be a misallocation of economic resources, lower gas prices in the short-run and higher in the long-run. The latter would occur because in the long-run the market would be served by an unregulated monopolist attempting to maximize his profits. This would be offset to a considerable extent by what happens in regard to wellhead and distribution regulation. It may be that deregulation of the pipeline segment would result in financial instability and poor service.

In addition, there might be a tendency for the pipeline to shun markets with a heavy residential load since these would generally be low load factor customers. Load factor is the ratio of total use to use at the peak. The line does best with high load factor customers since less storage is required to maintain throughput at optimal economic levels.

Further, deregulation might exacerbate the contract situation discussed earlier. Prices would be raised at the wellhead, and there would be no regulatory oversight to assure equity even for "old" gas. It thus would appear that the pipelines should be regulated in some manner.3/

This can take the form of either utility or common carrier regulation, or some combination of these. The major difference between the two is in what they sell. Under the utility concept, the pipeline is obligated to provide gas to those along its right-of-way who require that commodity. As a result, it must contract or purchase adequate supplies, store gas as necessary, and provide its customers with proper volumes at the appropriate time. Regulation, in this case, not only restricts entry to and exit from a market, but also establishes prices, sets standards for quality of service, and assures that there are adequate gas reserves to support operations. This is the status quo.

Under the common carrier concept, a pipeline is obligated to provide transportation services to those wishing to ship gas. Regulation, thus, only deals with the provision of this service. It would not be concerned with adequate gas supplies or gas quality, etc., except insofar as these factors affect the pipeline transportation function. The burden of adequate and reliable service would be carried by the distributors. The gas contract would be between the producer and the distributor.

Utility Regulation. The present system, as described earlier, results in the pipeline serving as the intercessor between the producer and the distributor. As such, the pipeline operator is the shipper, transporter, and marketer

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3/ For a discussion of a contrary view, see Tussing, Arlon R. and C.C. Barlow. The Rise and Fall of Regulation in The Natural Gas Industry. Public Utilities Fortnightly. March 4, 1982, pp. 15-23.

of the gas. In addition, there has recently been an increasing tendency for the pipelines to serve as a gas transporter for others.

In any case, the present regulatory regime as applied to the pipelines has generally resulted in adequate and reliable service for the customer, and financial stability for the utility. In addition, the system permits an adjudication of costs in an apparently equitable manner between the various parties, depending on the ability and bias of the regulators. Further, in a theoretical sense economic efficiency is supposedly optimized since the aim of economic regulation is to simulate competition. In any case, J.L. Callen concluded that, with all its faults, the net benefits from the current system were within 15 percent of his computed maximum. He felt it unlikely that other regulatory forms would do better.4/

In reality, however, the current system may be working against economic efficiency, assuming deregulation of natural gas at the wellhead. The pipelines may find themselves caught in a squeeze between rising wellhead prices on the one hand and a desire by state regulators to hold down distributor costs and rates on the other. As a consequence, the pipeline rate of return may drop below that needed to attract investment, and below what would result from a competitive market. Further, producers are prevented from competing for the distributor market, and distributors are prevented from competing for suppliers. This monopoly control of the market on one hand, and the control of supply on the other, can result in the pipeline becoming a price giver with a resulting disincentive for the producer to seek out new gas sources. The user would have an incentive to change to other energy forms where feasible.

4/ Callen, Jeffrey L. Production, Efficiency and Welfare in the Natural Gas Transmission Industry. The American Economic Review, June 1978, pp. 311-323.

In addition, gas ownership by the line can result in unequitable distribution of gas. That is, gas may be dedicated to a shrinking market simply because the line owning the gas goes there, while growing market areas may have difficulty in obtaining additional supplies of gas because of inadequacies in their line's sources of gas.

Common Carrier. In the case of common carrier status as generally defined, the pipeline serves as the transporter of the gas for a fee, available to all wishing to avail themselves of the service. The line has nothing to do with procuring or marketing the gas, but rather would be in a position akin to a railroad, moving natural gas from the producer to the distributor or user. A modification of this system is the oil pipeline. Here the transported oil is often owned by the producers and refiners who also own and operate the line as a separate entity. Shipment by others thus occurs on a space available basis.

Under the common carrier system, the pipeline could continue under regulation as to rates and service. Oil pipelines are not subject to direct rate regulation. Thus, adequate and reliable service should be assured, and the line could be prevented from exploiting its monopoly position. Further, since the distribution market would be opened to producers and supplies opened to distributors, competition for both should assure equitable availability of gas and prices. The increased competition should assure economic efficiency.

In addition, since the lines would no longer be concerned with the cost or price of gas other than transportation costs and price, their financial stability would be easier to assure and presumably would be a primary regulatory goal. This, of course, would be helped by the fact the lines would require less capital since the production and exploration part of the business would be handled entirely by others. That is, the total capital needed for a viable gas system would not change, but the amount needed by the pipelines would be less.

Common carrier status does have the disadvantage of forcing shippers to shop for transportation with the possibility that space might not be available when needed. Some form of long-term service contracts might replace the present purchase agreements. The common carrier has all of the other disabilities of a regulated system in terms of excessive regulatory lag, cumbersome procedures, and the possibility that rates will be set at a level that does not provide an appropriate rate of return.

There would also be problems for the line in scheduling shipments during peak periods and in assuring adequate revenues, unless shippers are able to contract for service on a long-term basis. Unlike the railroads, a gas pipeline carries a single commodity, and thus has a limited market for its services. It cannot depend on a flow of revenues from a variety of commodities to assure that its fixed costs will be covered under most economic conditions. Further, without the pipeline as an intermediary, there is a possibility that small distributors would have difficulty in obtaining adequate supplies of gas at competitive prices.

Some Observations

From the foregoing it is apparent that whatever regulatory regime is selected, it must permit the generation of sufficient revenues to cover the high fixed costs; these revenues must be relatively stable over the long-term to assure payment of debt service; competition should be permitted where feasible in order to permit all segments of the industry to react to market pressure and to optimize economic efficiency; the system should evolve out of the current arrangements in order to avoid problems with the many long-term contracts between the pipelines and producers on the one hand, and the pipelines and distributors on the other; and finally the regulatory arrangement should permit the lines to take advantage of economies of scale.

In regard to the latter, Kahn has noted that economies of scale exist up to the time where an additional line is required. After that, the economies tend to fade off into the sunset. This eventual lack of scale economy is countered by the need for coordinated planning, and the advantages accruing from such a centralized arrangement. Kahn notes that open competition occurs before the line is built, but not after. In his opinion common carrier regulation is the best way to achieve open competition, insofar as that is feasible.

We can evaluate the two basic kinds of regulation in terms of our criteria: sufficient, stable, long-term revenues; competition; evolutionary ability, and economies of scale. Utility regulation, in this regard, may not be able to fulfill the stable revenue and competition aspects. Assuming wellhead deregulation, the pipelines may find themselves caught in a squeeze play between rising wellhead prices on the one-hand and state regulators and consumers on the other. The result could be a decline in rate of return below what would be earned in a competitive market. Thus, revenues would neither be sufficient nor stable.

Further, because the pipeline contracts for gas on one hand, and sales on the other, under a long-term contract, there is a limited opportunity for competition anywhere in the system. That is, producers cannot compete for markets because their market is the pipeline, while distributors cannot compete for supplies because their supplier is the pipeline. This could be corrected to an extent by limiting the term of contracts to say 3 to 5 years, and requiring competitive bidding for renewals at least on the supply side; requiring the lines to make available a minimum percentage of capacity for carriage of gas for others; granting franchises to serve a market that are exclusive only up to the full capacity of the line, with subsequent service open through a competitive bid process. These changes would permit evolution of the system as conditions dictate, permit revenue stability over the long-term, but not necessarily in the short-term, encourage competition at both ends of the pipeline while exploiting economies of scale insofar as possible.

Alternatively, moving to full common carrier status could increase competition at both ends of the line with consequent promotion of economic efficiency. At the same time, since less capital would be required by the pipeline, its revenue requirement would be less. This would be countered by less revenue stability since there would be a limited assurance of the quantity of gas that would move through the line. This could be corrected by requiring contracts over a 1 to 3 year period for transportation of the minimum gas quantities.

Common carrier status does pose problems, however, in terms of access to capacity, tariffs levied on gas owned by the pipeline owners as a potential rebate to the owner, and the ability to deal with an emergency. The first two problems could be corrected by forbidding pipelines to carry gas owned or controlled by anyone having a financial interest in the line. This would be akin to the legal treatment accorded railroads, but contrary to that pertaining to oil pipelines. By the same token it would negate some of the most controversial aspects of oil pipeline regulation.

The emergency coordination aspects can be handled by giving FERC emergency powers under those conditions perceived to be an emergency. For example, a gas supply shortfall of a given percentage would permit FERC to specify rules and standards for the allocation of supplies.

There is, however, an additional difficulty. Producers might be reluctant to deal with small distributors except at very high prices because of the minor gas volumes involved. Pipelines might also be reluctant to accept such small volumes for shipment. The small distributor would lack market power in dealing with the producer. As things stand now, the pipeline procures the gas at the best available price, transports it, stores it if necessary, and finally delivers it to the distributor. Presumably many small distributors would lack the ability, financially and in a managerial sense, to accomplish the necessary tasks. This problem could be overcome by the formation of regional distributor associations to buy and store gas, or by a small distributor contracting with a larger neighbor to handle the chores for them.

In any case, because of the extensive use of long-term contracts, any effort to move to a common carrier regime will require a transition period of perhaps 5 to 10 years. An example of how such an arrangement might work is presented below.

An Example of the Steps Needed to Move to a Common Carrier Regime

1. Expiring supply contracts could only be renewed through competitive bidding, and only for limited terms not to exceed 5 years. Contracts expiring in the last 3 years of the transition period could be renegotiated to cover transportation and storage services only.
2. Existing contracts having more than 10 years to run, as of the initial transition date, could be limited to a 10 year term.
3. Pipelines could reserve an increasing percentage of capacity for common carriage. The reserved portion could be dependent on the expiration dates of existing contracts, but with the aim of 100 percent common carriage by the end of the transition.
4. Pipeline franchises could be limited to existing capacity. New capacity requirements could be served by anyone using selection criteria based on transport cost and service quality, or possibly through a bidding procedure. All new capacity would operate solely as a common carrier.

5. Gas transportation contracts could cover a guaranteed specific quantity at a given price plus specified tariffs for additional volumes. Prices could be set by negotiation or through the regulatory process. Contracts could cover a 3 year period.
6. Pipelines could be required to divest themselves of producing properties requiring transportation through their line within 5 years. If other properties are held, no exchange agreements would be permitted. No gas could move through a line if owned or controlled by anyone with a financial interest in the line after the 5th year.
7. Distributors could have the right to form associations for the purpose of negotiating for gas purchase and for transportation.
8. FERC's role during this period could be as adjudicator and mediator of disputes, as well as prescriber of standards to be met.

At the end of the transition period, the pipelines would operate as modified common carriers. They would provide transportation and storage services under moderate-term contracts negotiated between the line and the shipper. FERC would act as the mediator or court of first appeal in the event of disputes, or where it was felt equity had not been obtained.

The generalized system outlined above offers opportunities for the pipelines to adapt to the changed circumstances resulting from wellhead deregulation with minimal trauma by shifting to common carrier status. The changes needed to make the current system work have also been outlined.

In any case, it is apparent from the foregoing discussion that the optimal regime is one that preserves the benefits of the current arrangements, while providing many of the benefits perceived to flow from a free market. Either the utility or the common carrier system can achieve these goals, if appropriately modified.

APPENDIX IA

PEOPLE CONTACTED

In the course of this study discussions were held with the people listed below.

1. American Gas Association
   - Dallas Dawson
   - Don Schelhardt
   - Bruce Stroh
   - Randall Griffin
   - M. Armeac
   - Mike German
2. Association for Equal Access to Natural Gas Markets and Supplies
   - Hollye E. Cappleman
   - R. Charles Gentry
3. Association of Oil Pipelines
   - Patrick Corcoran
4. Edmund R. DuPont and Associates
   - Karetta Hubbard
   - Edmund R. DuPont
5. Independent Petroleum Producers Association
   - William Anderson
6. Interstate Natural Gas Association of America
   - Kenneth Thompson
7. Leva, Hawes, Symington, Martin and Oppenheimer
   - Joseph Swidler
8. Mid Con Energy Corporation (Peoples Gas)
   - Frederick Scott
   - Joseph Wells

9. Office of Pipeline Regulation, FERC

    Kenneth Williams

10. Process Gas Consumers Group

    Edward J. Grenier, Jr.

11. Tenneco, Inc.

    T. Paul Bulmahn

APPENDIX IB

A REVIEW OF REGULATORY THEORY*

Regulatory theory tends to revolve around the concept of a natural monopoly. This monopoly has the inherent tendency toward decreasing costs as more output is concentrated in a single supplier. This provides the potential for a public return from the creation of a monopoly. This behavior often stems from the necessity of making an initial heavy investment in order to be in a position to serve a given market. The more units of output that can absorb these high fixed costs, the lower the unit cost. Railroad tracks and pipelines are classic examples. The tendency toward declining average unit cost as the number of units sold increases is especially prevalent in the utilities because: 1) many have fixed and immovable connections between the supplier and customer; 2) services are largely nonstorable; 3) companies are under an obligation to supply services instantaneously on demand, and; 4) demands fluctuate widely from one point in time to the next. Therefore, utilities require a heavy investment to meet peak demand, and this is often most efficiently provided by one supplier. In short, the natural monopoly mode of utility operation often results in economic efficiency due to the presence of decreasing costs in the provision and utilization of these services.

Thus, regulation is generally implemented as a restriction on competition on the assumption that the customer can be served at least cost by a single supplier or a limited number of firms. In many cases this restriction is accomplished through the granting of an exclusive franchise. Territorial exclusivity is prevalent in the public utilties industry where it would be infeasible for companies to begin an operation without government permission. Protection against competition may also internalize benefits for the firm, prompting economically worthwhile investments that might otherwise not be made.

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* Prepared by Karen K. Nelson, Research Assistant - Office of Senior Specialists.

The consumer is believed to be protected by a natural monopoly by assuring him that the service he is getting is of adequate quality at a fair price. This can be done through licensing requirements, entry restrictions, and the like, to assure maintenance of certain known standards. In the absence of a natural monopoly, some industries can become destructive when competition forces marginal revenues to fall below average costs. It is held that rivalry will push prices down to marginal cost levels and total costs may not be covered for long periods of time, possibly resulting in lower quality service. Competition in public utility industries is, therefore, believed not to be in the public interest because it tends to reduce service quality and eventually raises costs. In addition, competition will be more intense in some markets and virtually nonexistent in others, an unfair and potentially injurious situation for some, if not all, customers. In this sense, competition can prove to be discriminatory when prices are cut to marginal costs in those markets where competitors meet, and held at monopolistic levels where they do not.

Another possible danger of competition if a regulated natural monopoly is not established is referred to as "cream-skimming". This practice occurs when market entry is unrestricted but competitors will enter only the most lucrative markets, leaving to established common carriers the burden of providing service to the less profitable markets. Public utilities that have been granted exclusive public franchises have assumed the obligations of a common carrier and thus have agreed to provide service to all segments of the market even if it is not always economical.

The preceding discussion has focused largely on efficiency, but recent changes in the public utility industries give rise to a greater need to discuss both equity and efficiency issues involved in regulation.[1]

The most significant change in the public utilities industry in the past decade has been a shift from plentiful supplies of fuels, declining costs, and easy plant siting, to rising costs, shortages, environmental concerns and market uncertainty. These new conditions make the intervention of government a prevalent factor in the management and operation of a utility. Public attitudes toward regulators have changed concurrently, requiring regulatory commissions to become more aggressive. A major concern for efficiency and equity issues is inevitable. This will be a challenge for regulation and require an investigation of alternatives in order to alter the current system accordingly. In the context of these changes, four different theories of regulation are discussed.

Public Interest Theory. The first theory of regulation that claims to explain the rational and effectiveness of regulation is the public interest theory. This is the oldest theory of regulation and is based on the premise that regulation's purpose is to protect the consumer from the abuses of monopoly power. This objective is accomplished by setting the firm's revenue requirements equal to the cost of providing service, including an allowable rate of return, and imposing an obligation to serve all comers so as to avoid a monopolistic restriction on output. Here, the rationale for government intervention is to promote efficiency and to assure a balance between the needs of investors, consumers, and the public at large.

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[1] Trebing, Harry. Equity, Efficiency, and the Viability of Public Utility Regulation. In Sichel, Werner, and Thomas G. Gies, eds. Applications of Economic Principles in Public Utility Industries. Ann Arbor, University of Michigan, 1981.

In practice, the regulatory body often considered itself an agent for consumer groups, negotiating and administering a relational contract. By the mid-1950s, the public interest theory was being attacked by various groups. Regulators were accused of being manipulated by the industries they were regulating, or of promoting from the start the objectives of the regulated industries, rather than providing protection to consumers. Other critics pointed to a lack of regulatory resources and expertise, and to the highly complicated procedures.

Capture Theory. A second theory of regulatory behavior is the capture theory or producer protection model which argues that the regulated firm, regardless of initial interest, will come to dominate regulatory decision making. The industry may actually employ the regulations directly to achieve its objectives, or the agency may consider the financial well-being of the industry to be in the public interest. In the 1960s and 1970s the capture theory was used as a framework for analysis of regulated industries.

This theory, however, suffers in ways which limit it as a tool for describing regulatory behavior. First, it does not explain those regulations that clearly are not in favor of the regulated industry. There are regulations that hamper a firm's performance and those that help in the attainment of its objectives. Secondly, the capture theory is a negative one that contributes little to the discussion of regulatory reform, resulting in the conclusion that the best change is to deregulate. Third, the theory does not adequately account for recent changes concerning the regulatory scene, such as citizen involvement and the expanding role of state regulators. These two groups could balance or negate some of industry's influence. Finally, the capture theory does not account for all the different actors that could be captors or captives. In sum, rather than curbing monopolistic practises, the capture theory equates efficiency with the cartelization of prices and output, with the fair treatment of cartel members the primary consideration, rather than a fair distribution of income between firm and customer.

Coalition-Building Theory. A third theory of regulation is coalition-building in which equity is a major consideration. It argues that the obtainment of the support of special interest groups is essential to the success of regulatory policy. Regulators achieve this by forming political coalitions and thinking in terms of the benefits and losses of a given rule for specific groups. Prices are set below costs for those groups whose support is actively sought, while other groups pay far in excess of costs, resulting in a large role for cross-subsidization and income redistribution in building the coalition. This theory can explain the practice of rate averaging, whereby the high costs of serving one group are spread among all groups. The theory holds the regulator will not attempt to protect the consumer from monopoly power, but rather will seek to build up political support by acting in favor of its constituencies. Equity and fairness take precedence over efficiency.

Again, this theory suffers from several shortcomings that limit its applicability. First, the policies implemented depend primarily on the objectives of the particular group of commissioners in office at that time. The theory cannot make any statement about the conditions that favor the public interest because the objectives of the various commissions will be different and indeterminate. Second, the regulator may not always have the power to do what the theory assumes he can. Third, the theory assumes regulators want to broaden their base of support when they actually have little need to do so. Fourth, it is very difficult to determine what, exactly, are the demands and preferred policies of a broad-based constituency. Finally, the coalition-building theory assumes that a group will necessarily behave differently merely as a result of regulation offering preferred treatment.

Equity-Stability Theory. The fourth and final theory of regulation to be discussed is the equity-stability theory. It explains regulatory behavior by putting forth the idea that legislators attempt to replace regular markets with governmental institutions which can make judgements on social issues in an effort to achieve fairness. The theory is based on the assumption that regulation occurs, not because markets are perceived to be inefficient, but because legislators are motivated to protect society from the negative effects of the operations of market forces. Regulation is, in this setting, expected to control the rate at which income is redistributed and provide the stability that a free market would not. Like the coalition-building theory, concentration here is on equity issues, but unlike the previous theory, does not rely on the building of a political base of support. The objective is to be fair to all groups. The weaknesses in this theory lie partly in its oversimplification and belief that Congress has acted clearly in favor of equity over efficiency. Also, the theory assumes public utilities are inherently efficient, a debatable point. Problems also arise as to who is to be given preferential treatment and when.

APPENDIX IC

A REVIEW OF NATURAL GAS TECHNOLOGY*

Technologic History

Though the general use of natural gas is of modern origin, natural gas has been known to man for literally thousands of years. References to burning springs, burning bushes, will-of-the-wisp, and so forth are quite probably the result of natural gas seepages from the earth, some of which were accidentally or intentionally ignited. Definite sightings of natural gas fires are reported as early as 900 B.C., and such historical figures as George Washington and Julius Caesar commented on sightings on burning springs.1/

The earliest use of natural gas in the United States is recorded as having been in 1821 in Fredonia, New York. A shallow well was dug at the location of a natural gas seep that had been accidentally ignited by a group of small boys. The gas was piped to a nearby inn where it was used for illumination. However, the use of gas for illumination and other purposes actually began in the United States about five years earlier, with the use of manufactured gas produced by the roasting of coal in the absence of air. Widespread use of natural gas in place of manufactured gas, however, did not take place in many American cities until just before the middle of the twentieth century, when adequate pipeline service for natural gas became widely available.

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* Prepared by Langdon T. Crane, Specialist in Science and Technology - Science Policy Research Division.

1/ United States Federal Power Commission. National Gas Survey. The Commission Report. Volume I. Washington, U.S. Govt. Print. Off., 1975. p. 17.

Thus, even though gas was commonly used in many major cities of America for decades, it was only the cities in proximity to natural gas fields that were able to use it. The rest relied on manufactured gas of various types, generally having 50 percent or less of the heat content of natural gas. Because of the inability to transport natural gas over great distances, prices for natural gas at the wellhead remained low. Where possible, industry attempted to take advantage of these low prices, and often located accordingly. Even with this industrial interest, the demand for natural gas remained far below production capabilities during the last quarter of the nineteenth century and thereafter.

It was not until the mid-twentieth century that annual demand began to exceed the annual new supply. In fact, natural gas was so plentiful prior to this time, and prices so low, that it was common for natural gas to be vented (blown into the air) or flared (burned) rather then taking the trouble to cap gas wells or to recover the gas from oil wells. Natural gas was also used to produce carbon black, a material employed in the manufacture of rubber products and printer's ink and produced by the incomplete combustion of natural gas or petroleum. The process is viewed as wasteful by conservationists because the heat from the combustion is generally discarded.2/

This waste and inefficient use of natural gas through venting, flaring, and carbon black production continued to increase during the first quarter of the twentieth century. By 1935 and continuing until 1948 almost half as much gas was wasted as was used. Without adequate pipelines, demand was generally

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2/ In 1980, only 0.16 Tcf of the 21.48 Tcf of natural gas extracted was vented or flared, and carbon black production was employing about one-third of the amounts of gas that is vented or flared. See U.S. Federal Power Commission National Gas Survey, Volume I, p. 25 and U.S. Department of Energy. Energy Information Admininstration. 1980 Annual Report to Congress, V. II. DOE/EIA-0173(80)/2, March 1981. Washington, 1981. p. 103.

far below production capacity. And as demand for petroleum products began to grow following the advent of the automobile, the situation for gas became even worse because gas and oil are so often found in association that the quest for petroleum produced an ever worsening glut of natural gas. This glut was a continuing problem that persisted until a large scale network of long distance pipelines was constructed so that more natural gas could reach the market.

The history of the establishment of today's pipeline system is less a tale of technological conquest than of sheer perserverence, backed by a healthy amount of entrepreneurship occasionally laced with business practices that exemplified the most aggressive traditions of private industry.[3] In keeping with the purpose of this section, the discussion provided here will only deal with the engineering and technical facets of this story, leaving the financing and legal aspects to other sections.

The first attempt to transport natural gas in large amounts in the United States ended in failure due to an extremely poor choice of pipeline material. The intent was to transport gas to the city of Rochester, New York, from gas fields about 25 miles away via an eight inch pipeline made from hollowed-out pine logs, which leaked too much to be serviceable. The first successful transmission pipeline appears to have been constructed two years later, in 1872, when a two-inch-diameter wrought iron pipeline was constructed over a distance of five miles to Titusville, Pennsylvania, from a nearby oil field. The line carried 400 Mcf per day to serve 250 residential and industrial customers.

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[3] The history of the natural gas industry is briefly recounted in Vol. I of the National Gas Survey, op. cit. Events leading to the passage of the Natural Gas Act of 1938 culminated with Congress' examination and exposure of the activities of the insull empire of utility holding companies, which was analogous in importance for the Natural Gas Industry to the importance of the Rockefeller control of Standard Oil for the Petroleum Industry.

Pipeline technology was relatively static for the next two decades. A number of pipelines were built during that period using wrought iron pipe sections connected with screw couplings. Diameters ranged up to about eight inches, but pressures remained fairly low -- wellhead pressures were generally employed, though pressure was sometimes supplemented by a pump at the wellhead. Distances were generally short as well, so that natural gas users were limited to geographical areas in proximity to oil and gas fields. Throughout this period, and extending well into the twentieth century, much of the gas that was piped was from fields that were comparatively small in capacity and quickly depleted, especially under the practices of that time. Many of the pipelines that were built were only used for a relatively few years, and customers faced a serious problem of intermittant, or totally curtailed, supplies.

The first high pressure (525 psi) pipeline in the United States was constructed in 1891, and covered a distance of 120 miles from northern Indiana to Chicago. The importance of high pressures in gas transmission is 1) that gas volume decreases with increasing pressure, so that a greater quantity of gas (in terms of its volume at the low pressures at which it is used) can be transmitted at any given velocity of gas in the pipe, and 2) that the velocity of the gas in the line increases as the "pressure drop" along the line (i.e., the difference in pressure between the input and output ends of the line) is increased, because it is the pressure drop that serves to push the gas through the line. With higher pressures the gas is compressed more, and higher pressure drops are able to be sustained. It is clearly worth employing large pressures and large pipe diameters wherever customer demand and economics permit.

One of the major problems with the early high pressure lines was the leakage of gas at the bolted junctions between sections of pipe. Some of the old bolted low pressure pipelines lost from 20 to 40 percent of the gas in transit through leakage, and the use of high pressures tended to make the problem worse. Still, pipelines provided the only economic means of transporting natural gas from the fields to the cities, and so pipelines continued to be built. Prior to 1920, most of the pipelines were less than 200 miles in length. Cincinnati was served by a 183 mile pipeline; Cleveland by a 120 mile pipeline; and Los Angeles by a 150 mile pipeline. The first large diameter line, 16 lines in diameter, was constructed during the 1910-1920 decade to service Kansas City from gas fields in eastern Kansas.

The big breakthrough in pipeline technology came with the construction in 1925 of a 217 mile all-welded line from northern Louisiana to Beaumont, Texas. It used 14, 16, and 18-inch diameter pipe with sections joined by acetylene welds rather than by bolts. This provided a vast improvement in the leakage problem, that ultimately led to today's leakage levels of less than one percent of the transmitted gas and permitted the practical construction of much longer pipelines. In 1926 a 22-inch diameter line 260 miles long was built to service New Orleans and Baton Rouge. In 1927 a 340 mile line was built from Texas to Colorado. Then the first 1000 mile line was built in 1931 from the Texas Panhandle to Chicago, a 24 inch line of welded steel. That same year saw the completion of major pipelines from Texas to Indiana (later to be extended to Detroit), from Kentucky to Washington, D.C., and from Texas to Omaha and Minneapolis. These pipelines were highly successful and confirmed the capabilities of the high pressure long distance pipeline technology. The distribution of natural gas on a national scale was now a real possibility.

Though the basic elements of today's modern pipeline systems were incorporated in these innovative early long lines that were built in the early 1930s, a great many improvements have been made since. Among these are the use of larger diameter pipes, up to almost 50 inches in diameter in some cases; the use of higher tensile strength steels to reduce the volume of steel required, thereby limiting both costs and the mechnical problems of unnecessary weight while permitting higher pressures; higher horsepower compressors of improved design; improved welding and welding quality control techniques; automatic ditch digging machinery; improved corrosion resistance; automated monitoring, control and operation of pumping substations and other essential functions; and improved maintenance and safety technology. Of course, not all of this technology was developed for or by the gas pipeline companies; much of the work was performed in connection with developing petroleum pipelines.

The Technology

Natural gas must be processed, compressed, transported and stored before it reaches the ultimate consumer. We will now turn to a discussion of the required technology in that order.

Processing.

The function of natural gas processing stations is to separte the natural gas from petroleum and natural gas liquids and to purify the natural gas of undesirable pollutants of varioue types, primarily sulfur, water vapor, carbon dioxide, and nitrogen. Though a good deal of natural gas processing is performed at the wellhead as a part of the gathering system, the overall processing of the natural gas is crucial to the operation of any natural gas pipeline. Thus it seems appropriate to mention the processing operations here as though these were an integral part of pipeline systems.

Separating Natural Gas from Petroleum.

When gas and oil are produced in conjunction with each other, or when the natural gas is essentially dissolved in the petroleum from an oil well, the first step in processing is to separate the gas from the oil. Several basic types of separators are customarily used, but can essentially be classed according to three types of operation. One is termed a labyrinth unit, which directs a gas-oil stream through a maze consisting of either a rigid fabricated baffle structure or a random packing of ceramic material. The principle of operation is that high turbulence and abrupt changes in direction of the stream will force liquid droplets from the stream to be deposited onto the obstructing surfaces because of their greater density and inability to change direction. There are definite velocity limits allowable for the stream: too low a velocity will fail to result in the necessary turbulence or to bring the oil droplets into contact with the collection surfaces, whereas too high a velocity will produce excessive trubulence that will, in turn, result in re-entrainment of the liquid to produce actual flooding of parts of the separator. This type of separator is said to be sensitive to the amount of liquid to be handled, and thus on the amount of gas that can be processed. Also, its configuration makes it susceptible to clogging by the solids encountered in field production and quite difficult to clean.4/

Another common type of separator, termed a centrifugal unit, employs centrifugal separation. The gas-oil stream is injected into a cylindrical container along a tangential path, which spins the gas around the interior surface of the container. With the axis of the cylinder in a vertical direction, and the intake opening approximately midway from bottom to top, the heavier particles tend to fall to the bottom and the lighter gas to diffuse upward. The centrifugal acceleration forces the petroleum vapor particles toward the physical surface of the cylinder, where it condenses and runs downward. The trapped liquid is maintained in a quieting chamber at the bottom of the separator cylinder to allow for further degassing of dissolved natural gas and other volatiles. The

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4/ For more information on this, and the other equipment discussed below, see American Gas Association, Gas Engineers Handbook.

gas exits at the top of the cylinder through a final scrubbing element, usually consisting of a combination centrifugal and labyrinth unit. Centrifugal separators have few closely spaced elements and are therefore difficult to overload with liquid, except for the final scrubbing unit which will only be exposed to a small liquid load.

The third common type of separator is termed a horizontal unit, and might appear at first examination to bear some similarity to a labyrinth unit because it, too, employs internal baffles as liquid collectors. However, in this case the baffles have a very different configuration. The separator is in the form of a horizontal cylinder, in which the gas-oil mixture flows axially. The entrance chamber of the separator contains a system of loosely spaced baffles to trap and remove oil entering the unit in "splatters" or large drops, leaving only very small drops and vapor to enter the main unit. The main separator unit is filled with closely spaced parallel plates oriented parallel to the axis of the separator but inclined at a sufficient angle to the horizontal plane that the collected liquid will run off rapidly. These plates are spaced closely enough that oil droplets above a certain size will fall far enough before traversing the full length of the separator that they will strike one of the plates. Liquid running off the collector plates enters a quieting chamber for degassing.

Reducing Water Vapor. Water vapor can create serious problems in natural gas transmission lines via three different mechanisms. First, water vapor can freeze, thus clogging ports, nozzles and ultimately the pipes themselves if the situation becomes sufficiently extreme. Second, solid compounds known as hydrates can be formed by chemical combinations of hydrocarbons and water under pressure, again producing solid blockage of the lines. Many of these hydrates freeze at temperatures well above the freezing point of water, or are solids at most temperatures at which pipelines are operated. Finally, natural gas can form complexes with water molecules (clathrates), which are a particular form of hydrate in which the water molecules become bound to each other in a hollow spherical array that encloses several natural gas molecules. This substance can freeze as well.

One approach to handling hydrate stoppages, which are the primary cause of pipeline blockage, is ad hoc: either the pressure can be reduced or the temperature increased in the region of the blockage. Another is to introduce inhibitors, such as methanol, to reduce freezing points of hydrates and water vapor. The favored method, however, is to dehydrate the gas by absorbing the water vapor with triethylene glycol. This is accomplished by passing the natural gas stream through a chamber in which glycol droplets are counterstreamed, with the natural gas customarily flowing upward and the glycol downward to collect in the bottom of the chamber after interacting with the water vapor. The glycol exits to a chamber where water is removed by boiling, and the purified glycol is then recycled to absorb more water from the natural gas stream. Using this technique, dew point depressions of as much as 75°F can be obtained, thereby significantly reducing the possibility of hydrate formation and of freezing of water vapor.

Sulfur and Carbon Dioxide. Sulfur compounds and carbon dioxide are two important impurities of natural gas, and are often, though not always, removed by a single process. Gas from many fields contains no sulfur and very little carbon dioxide, and presents no purification problem with respect to those two substances. Gas from some very large fields in the U.S. and Canada, however, may contain up to 46 percent of sulfur compounds (mainly hydrogen sulfide plus mercaptans and traces of other organic sulfides) and the customary range of carbon dioxide is from about 0.1 to about 6 percent (all percents being by volume). In some cases the carbon dioxide content ranges significantly higher. While the sulfur compounds are chemically reactive and can damage the pipeline and associated machinery, carbon dioxide is less harmful. It does, however, reduce the heat content of the gas.

The most common method of reducing sulfur compounds and carbon dioxide is effective for both hydrogen sulfide and carbon dioxide. In this process, water solutions of either monoethanolamine or diethanolamine are employed to trap hydrogen sulfide and carbon dioxide at room temperatures by flowing the aqueous solution downward through a bubble tower (a vertical array of perforated trays containing the liquid solutions) through which the contaminated gas is forced to flow upward. After absorbing the contaminants, the aqueous solution is regenerated by heating to about 180-200°F. Another method employs hot potassium carbonate to absorb the carbon dioxide and hydrogen sulfide. Further heating of the potassium carbonate then releases the contaminants, thereby regenerating the potassium carbonate. Still other processes are used for the removal of hydrogen sulfide or carbon dioxide alone, and for removing mercaptans.

Removal of Nitrogen. Nitrogen is another of the major contaminants of natural gas, with concentrations commonly falling in the range from 11 to 16 percent. Sometimes nitrogen concentrations are as high as 28 percent in wells that are now in use to supply pipelines in the United States, though many U.S. reserves contain as little as 5 percent nitrogen or less. While concentrations below about 5 percent are not regarded as objectionable, higher nitrogen concentrations tend to reduce the heat content of the gas. Also, nitrogen affects the flow characteristics of the natural gas in pipelines. This is desirable to minimize nitrogen content in natural gas, though nitrogen does not pose a problem from the standpoint of its chemical action on pipelines and machinery.

Unfortunately, the methods employed for the removal of nitrogen from natural gas are energy intensive, and therefore comparatively expensive. While a number of processes have been proposed and patented for removing nitrogen by selective absorbtion of nitrogen by some material or other that could be regenerated and reused, as with the use of monoethanolamine to absorb hydrogen sulfide and carbon dioxide, such processes have not been widely employed. The primary method now used in the U.S. for removal of nitrogen is cryogenic: the temperature of the natural gas is reduced far enough to liquify the natural gas, but not so far as to liquify the nitrogen, whose boiling point lies below that of natural gas. The liquid natural gas can then be separated from the nitrogen and any other contaminants whose boiling point lies below that of natural gas. Ultimately, the natural gas is warmed once again to room temperature and restored to its gaseous state. The reason that this method of separation by liquifaction of the natural gas is so energy intensive is that natural gas does not liquify until a temperature of -265°F is reached, which means that a very large amount of cooling is necessary in order to make the process work.

Were it not for the fact that the very useful but quite rare gas called *helium* is generally found in association with nitrogen in natural gas, it would seem doubtful that efforts would be made to remove nitrogen from natural gas, except where nitrogen concentrations are *very* high. Where nitrogen is removed from natural gas, it is because of commercial interest in the associated helium rather than because of the deleterious effects of nitrogen on the combustion properties of the host natural gas. Since the concentration of helium is roughly proportionate to, but always considerably less than, that of the nitrogen that is present (a 28 percent contamination of nitrogen is generally associated with roughly a 2 percent helium concentration; a 15 percent concentration of helium, and so forth), it is profitable to seek to remove the nitrogen-helium mixture from natural gas only when the nitrogen concentrations are fairly high. Thus, it is that only about one-third of natural gas containing appreciable quantities of nitrogen -- only when the nitrogen content lies about 15-20 percent -- is purified of nitrogen. If the nitrogen is not removed, the heat content of the gas is reduced in proportion to the (non-combustable) nitrogen present and may fall below the regulated standard of 960 Btu per cubic foot. In such cases it is common practice to "fortify" the gas with propane or one of the other natural gas liquids whose heat content is greater than natural gas.5/

Natural Gas Liquids. The last major class of "contaminants" of natural gas are the liquid hydrocarbons known as natural gas liquids. As mentioned earlier, these include ethane, propane, butane, pentane, and octane. These combust with heat content per unit volume well above that of natural gas. Though vapors of these liquids are often used to "fortify" natural gas to meet the combustion standard of 960 Btu per Mcf, their greatest value is quite independent of natural gas, for they are used as valuable chemical feedstocks and as readily transported fuels or as additives to gasoline.

The most common method of extracting the natural gas liquids from natural gas is by absorption in oil, followed by distillation of the absorbant oil. The absorption takes place in a bubble column or other device which ensures intimate and prolonged contact of the gas with the absorbing oil. The gas flows upward, the oil downward under the influence of gravity. The greater the ambient pressure, the greater the absorption of natural gas liquids. On the other hand, the greater the temperature, the lower the absorption of natural gas liquids. Since pumping the gas to high pressures is not only expensive but

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5/ The discussion regarding nitrogen removal is based on an extensive telephone conversation with Dr. Philip Tully of the Helium Station of the United States Bureau of Mines in Amarillo, Texas.

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also serves to increase the temperature of the gas -- which can of course be cooled, but only at additional expense -- it is generally not practical to seek optimum pressures and temperatures for absorption. Thus some compromise is typically made between recovery rates of the natural gas liquids and expense.

After the oil has absorbed the natural gas liquids, it is fractionally distilled for individual recovery of each of the respective natural gas liquids constituents. Alternatively, natural gas liquids are sometimes recovered at moderate efficiencies by cryogenic techniques. The natural gas is cooled under pressure to termperatures sufficient to liquify the natural gas liquids, which are then separated from the natural gas itself (which remains in gaseous form) and fractionated to separate the various natural gas liquids constituents from each other.

Compression. Compressor stations are an essential part of any modern transmission system. As mentioned earlier, the purpose of compression is twofold: to reduce the volume of the gas being shipped, and to drive the gas more rapidly through the pipeline. In addition to serving that function, compressor stations are used to inject gas into storage reservoirs, to move gas from low pressure wellheads and through the gathering lines to the transmission systems, and to pressurize and move gas in the distribution systems that serve to carry gas from the transmission systems to the final customers. The following discussion is primarily applicable to compressor stations associated with transmission lines, where volumes of gas are very large and pressures generally range from 200 psi to as high as 1300 psi.

It is absolutely essential that gas entering a compressor station first be cleansed of dirt or grit that has been picked up from the piping upstream, and that it be dehydrated to ensure that it is dry. Next comes the actual compression of the gas to the desired pressure. The type of machinery selected for a particular compression station will depend on a number of factors, the most significant being the magnitude of the compression increase to be achieved. If large compression increases are needed at a particular point, then it will be advantageous to select one type of machinery, whereas if low compression increases are desired, then other types of machinery might be preferred, as outlined below. Thus it is often advantageous to use one type of machinery for the initial pressurization of the gas at the input end of the pipeline, and other types of machinery for the relay stations along the line.

The two types of compressors commonly used on transmission lines are the centrifugal and the reciprocating. The centrifugal pump employs a rotating impeller to propel the gas at high velocity in a radial direction, thereby increasing the static pressure of the gas without confining and squeezing it, as occurs in a reciprocating compressor which uses a piston to compress the gas in an enclosed cylinder.

Each of the two types of compressors have specific advantages and disadvantages. The centrifugal compressors are capable of handling fairly large variations in load by changing the speed of the rotator, and require considerably less horsepower to operate at low loads than at high. Howeve , they are only able to increase pressures by relatively small amounts: typical ratios of output pressure to input pressure per stage range from about 1.1 to 1.4. Reciprocating pumps are capable of higher ratios of output pressure to input pressure, typically ranging from about 1.2 to 5. However, they are not able to be operated at partial loads as well as centrifugal compressors, and their horsepower requirements tend to remain more constant when loads are reduced than is the case with centrifugal compressors. In fact, reciprocating compressors require more energy to operate than centrifugal compressors in the ranges of input pressure/output pressure ratios where both types of compressor are operable, say from pressure ratios of 1.2 to 1.4.

The advantage of reciprocating compressors over centrifugal compressors comes when large enough pressure ratios must be obtained that the choice is between a single stage reciprocating pump versus a multiple stage centrifugal pump. In that case it is generally found that the multiple stage centrifugal compressor requires more energy to operate than a single stage reciprocating compressor, though the multiple stage centrifugal compressor will still have the variable load advantages mentioned above and will not produce pressure pulsations as reciprocating compressors do. However, energy costs are always a major consideration in the design of compressor stations because of the tremendous amounts of power required. For instance, a typical 30-inch diameter pipeline operating at about 800 psi would have a capacity of about 610 MMcf per day, and might require compressor stations having operating capacities of about 6100 horsepower at 75 mile intervals. Very large pipelines operating at higher pressures typically have compressor stations of 12,000 to 15,000 horsepower, spaced at such intervals over distances of 1000 to 1500 miles. Design engineers must make many compromises between energy consumption, initial cost of equipment, and reliability and maintenance costs in selecting compressor station machinery.

One of the major recent advances in pipeline technology has been the automation of compressor stations, allowing entire pipeline systems to be operated remotely from a central point without the need for local operators. Since compressors can often be economically fueled by gas from the pipeline, human involvement is very limited.

Transportation. The design of the piping itself can be a major factor in the overall design of a transmission pipeline. The delivery rate of the gas is, of course, a fundamental consideration. However, flow rates are a complicated function of the pipe diameter, the velocity of flow of the gas in the pipe, and the pressure of the gas in the pipeline. As the diameter of the pipe increases, the smoothness and ease of flow of the gas in the pipe increases as well because of the reduced turbulence resulting from interactions of the gas with the walls. Thus, the flow of a gas through a pipe increases more rapidly than the increase in cross section of the pipe as the diameter is increased. On the other hand, the cost of the tubing for the pipeline will increase at least in proportion to the diameter, as well as in proportion to the wall thickness of the tubing used in construction.

Since higher pressures require thicker tubing, and easy flow permitting lower horsepower for compression stations requires larger diameters, many compromises must be made in selecting the size of the pipe to be used. Occasionally it is advantageous to "telescope" the pipeline, using thick-walled tubing near the compressor stations where pressures are the highest and using pipe of decreasing thickness as the distance from the compressor stations increases. However, this too imposes constraints on the operation of the pipeline system, because of the fact that the pressure drop along the line decreases as the velocity of flow decreases. Therefore, if the line is to be operated below capacity, the pressure supplied by the compressor stations must be reduced to avoid putting excess stress on the thin-walled sections of the line. This means that the compressor stations must be capable of more variable operation than would be necessary if the line were not telescoped, and it might make it more difficult to maintain equilibrium flow conditions in the line for certain flow rates.

Storage. Underground storage provides an excellent means of 1) temporarily expanding the availability of natural gas during periods of peak demand, and 2) maintaining pipeline operations at, or near to, capacity in periods of low demand. Now that industrial users are making less use of interruptable gas service during periods of slack demand, underground storage has taken on greater significance in pipeline operations. Roughly 50 percent of the Nation's current underground storage capacity is owned by interstate gas pipeline companies, the remainder being owned by distribution companies and intrastate pipeline companies. Total storage capacity in 1980 was about 7.3 Tcf.

The operation of an underground gas storage reservoir is relatively simple in principle. Gas is pumped into an underground geological structure, such as a depleted gas field, an aquifer, a depleted oil field, or some other impervious geological structure, and is available for use as needed. It is important to store the gas under as much pressure as possible because the delivery rate from the reservoir decreases rapidly with decreasing pressure. For instance, the National Gas Survey6/ points out that the Chippewa Field in Ohio has a daily delivery rate of 25 MMcf when it is fully pressurized at 1000 psi, but that the delivery rate falls to only 8 MMcf per day when the pressure is 500 psi and 4 MMcf per day when the pressure has fallen to 400 psi. With such a relationship between pressure and delivery rate, it is clear that not all of the gas in a storage reservoir can be extracted under practical operation. Part of the gas must be kept in the reservoir simply to push the "working gas" out of the reservoir so that it can be used. The gas that remains in the reservoir is called "cushion gas" or "base gas", and typically amounts to about 58 percent of the gas in the reservoir system as a whole.7/ Thus, of the 6.3 Tcf of natural gas actually in storage in the United States in 1980, only 2.6 Tcf was working gas.

6/ U.S. Federal Power Commission. National Gas Survey, vol. I, p. 46.

7/ U.S. Department of Energy. 1980 Annual Report to Congress, p. 109.

Other types of storage are employed in natural gas systems as well, though generally these are employed by distributors rather than the transmission pipeline companies. In addition to natural gas stored underground (in this case by the distributor rather than by the transmission company), the distributor would employ stored supplies of synthetic gas, of natural gas that had been liquified and stored at the very low temperature of -265°F, and some amount of propane -- one of the natural gas liquids. These would of course be stored and employed according to a least-cost strategy, with the cheapest fuels being used to the greatest extent.

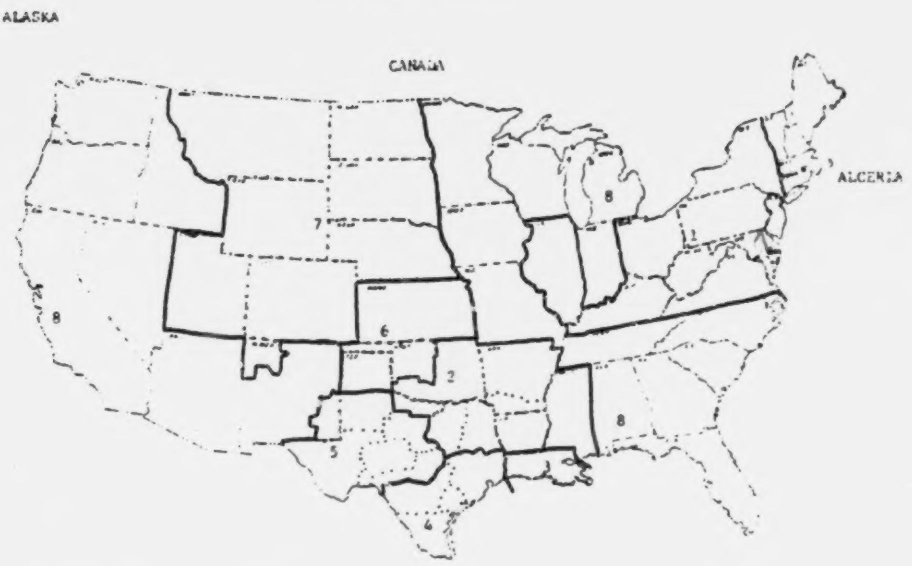
APPENDIX ID

GAS SUPPLY AND MARKET AREAS

Source: Federal Power Commission. Bureau of Natural Gas. National Gas Flow Patterns 1975. February 1977, pp. 15-16.

MAP 2

1975 GAS SUPPLY AREAS

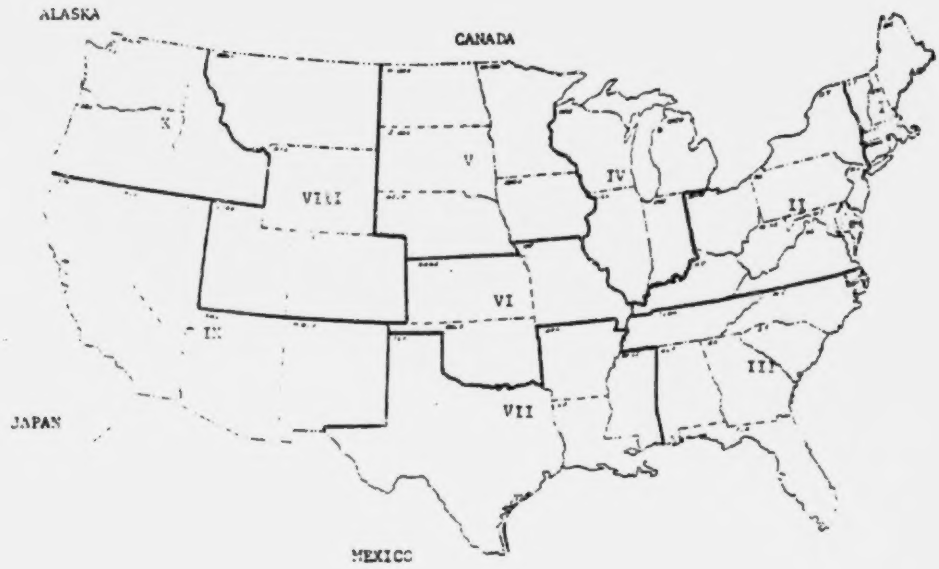


KEY TO SUPPLY AREAS

Major Supply Area	Subareas
1 Appalachian - Illinois Basin	Illinois Kentucky Maryland New York Ohio Pennsylvania Virginia West Virginia
2 Other Southwest	Arkansas - Northern Arkansas - Southern Louisiana - North Mississippi Oklahoma Other Texas R.R. Dist. 5 Texas R.R. Dist. 6 Texas R.R. Dist. 9
3 South Louisiana	Louisiana - South Onshore Louisiana - South Offshore
4 Texas Gulf Coast	Texas R.R. Dist. 1S Texas R.R. Dist. 2 onshore Texas R.R. Dist. 3 onshore Texas R.R. Dist. 4 onshore Texas - Offshore
5 Permian Basin	New Mexico - Southeast Texas R.R. Dist. 1N Texas R.R. Dist. 7B Texas R.R. Dist. 7C Texas R.R. Dist. 8 Texas R.R. Dist. 8A
6 Hugoton - Anadarko	Kansas Oklahoma Anadarko Oklahoma Panhandle Texas R.R. Dist. 10
7 Rocky Mountain	Colorado Montana Nebraska New Mexico - Northwest North Dakota Utah Wyoming
8 Other Areas	Alabama California Florida Michigan Other
Alaska	
Gross Imports	Algeria Canada

MAP 3

1975 GAS MARKET AREAS



KEY TO MARKET AREAS

Major Market Area	Subarea
I New England	Connecticut Maine Massachusetts New Hampshire Rhode Island Vermont
II Appalachian	Delaware District of Columbia Kentucky Maryland New Jersey New York Ohio Pennsylvania Virginia West Virginia
III Southeast	Alabama Florida Georgia North Carolina South Carolina Tennessee
IV Great Lakes	Illinois Indiana Michigan Wisconsin
V Northern Plains	Iowa Minnesota Nebraska North Dakota South Dakota
VI Mid-Continent	Kansas Missouri Oklahoma
VII Gulf Coast	Arkansas Louisiana Mississippi Texas
VIII Rocky Mountain	Colorado Montana Utah Wyoming
IX Pacific Southwest	Arizona California Nevada New Mexico
X Pacific Northwest	Idaho Oregon Washington
Alaska	
Gross	Canada Mexico

BOOK II

STATE REGULATION OF DISTRIBUTION

Prepared for the
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STATE REGULATION OF NATURAL GAS DISTRIBUTION UTILITIES

Although Federal legislation and regulation have been the dominant factors in controlling the prices and service policies of natural gas producers and natural gas transmission companies, State regulation is the dominant factor in controlling the prices and service policies of the public utilities that distribute natural gas to local customers.

During the mid-nineteenth century, local governments began granting local franchises to permit the local manufacture and distribution of gas, and in 1885 the State of Massachusetts established for the first time a Board of Gas Commissioners with state-wide supervisory powers over corporations manufacturing gas for fuel and lighting. By the end of World War I, most states had established a commission, usually called either a public service commission or a public utility commission, to ensure adequate service at a fair price from holders of gas and other utility franchises.

As the technology for long distance pipeline transmission of gas matured in the decades after 1920, locally manufactured gas gave way to underground natural gas as the commodity distributed by local utilities. Until the 1970's, the well-head price of natural gas and the cost of pipeline transmission were low, hence prices to the end user were low. As these costs increased during the 1970's, state regulatory agencies felt increasing frustration in their efforts to regulate local gas rates because control of well-head prices and transmission rates lay in Federal hands.

Today, a large number of gas distribution utilities and gas pipelines are under state agency jurisdiction. There are 1,328 privately-owned and 1,064 publicly-owned utilities operating under state jurisdiction. Texas contains the largest number of privately-owned utilities (325), and Florida contains the largest number of publicly-owned utilities (111). Hawaii and the District of Columbia have the least number of privately-owned utilities, 1 each; and 16 state agencies regulate no publicly-owned utilities. There are 936 privately-owned gas pipeline companies and 400 publicly-owned pipeline companies under state agency jurisdiction. Only one state, Nebraska, regulates no privately-owned pipeline companies, but 33 states regulate no publicly-owned gas pipeline companies.

In this part of the report, three aspects of state regulation of gas distribution are examined. First, the current status of the regulation of natural gas distribution utilities by regulatory agencies in the fifty states and the District of Columbia is discussed. This discussion covers the scope of state authority and also the major issues and problems currently faced by state regulators. Second, the extent to which gas distribution utilities qualify for "natural monopoly" status and for exclusive franchises to serve an area is examined. The main focus of this analysis is on the characteristics and behavior of the companies in the industry and on the opportunities for competition. Third, the impact of Federal regulation on State regulation is considered.

The Scope of State Authority

State public utility commissions have a wide range of authority for regulating the gas industry. Most state public utility commissions have the authority to regulate retail rates for natural gas charged to the ultimate customer. The authority of state commissions to regulate wholesale rates for natural gas, however, is much more limited. Most states also regulate rates for gas transmission for other distribution companies. State commissions also have the authority to initiate gas rate investigations and often to prescribe temporary rates, as well as to suspend proposed rate filings.

State public utility commissions often have authority to approve the issuance of major securities before issuance and to approve major corporate transactions.

Most state public utility commissions have the authority to regulate safety standards for gas, to regulate interconnections of privately-owned companies, to regulate the attachment of new customers and loads, and to prescribe regulations concerning shortfalls and curtailments of gas service. Also, most state public service commissions require certification of convenience and necessity before allowing major additions to gas transmission lines.

An overview of state regulatory authority is presented here, and the detail of state public utility authority to regulate gas is discussed in the appendix.

A summary of state regulatory agencies' more important authorities to oversee and evaluate the gas rates of privately-owned and publicly-owned gas utility companies is presented in table 1. This table, which is derived from appendix tables A-1, A-4, and A-5, shows the authorities of 51 utility regulatory agencies (the 50 states and the District of Columbia) to deal with gas rates in three ways: (1) to regulate rates for retail natural gas sales by privately-owned and publicly-owned gas utilities, (2) to

TABLE 1*

STATE AGENCY AUTHORITY TO REGULATE RETAIL RATES FOR NATURAL GAS, TO INITIATE GAS RATE INVESTIGATIONS, AND TO SUSPEND PROPOSED RATE CHANGES BY STATE, 1979

Column Agency	(1) Sales to Ultimate Consumers by Private Companies	(2) Sales to Ultimate Consumers by Public Companies	(3) Initiate Rate Investigations of Private Companies	(4) Initiate Rate Investigations of Public Companies	(5) Suspend Proposed Gas Rate Changes by Private Companies	(6) Suspend Proposed Gas Rate Changes by Public Companies
Alabama	Y	N	Y	N	Y	N
Alaska	Y	Y	Y	Y	Y	Y
Arizona	Y	N	Y	N	N	N
Arkansas	Y	N	Y	N	Y	N
California	Y	N	Y	N	Y	N
Colorado	Y	Y 1/	Y	Y 2/	Y	Y 3/
Connecticut	Y	N	Y	N	Y	N
Delaware	Y	N	Y	N	Y	N
D.C.	Y	N	Y	N	Y	N
Florida	Y	N	Y	N	Y	N
Georgia	Y	N	Y	N	Y	N
Hawaii	Y	N	Y	N	N	N
Idaho	Y	N	Y	N	Y	N
Illinois	Y	N	Y	N	Y	N
Indiana	Y	Y	Y	Y	Y	Y
Iowa	Y	N	Y	N	Y	N
Kansas	Y	Y 1/	Y	Y 2/	Y	Y 3/
Kentucky	Y	N	Y	N	Y	N
Louisiana	Y 1/	N	Y	N	Y	N
Maine	Y	Y 1/	Y	Y 2/	Y	Y 3/
Maryland	Y	Y	Y	Y	Y	Y
Massachusetts	Y	Y 1/	Y	Y	Y	Y
Michigan	Y	N	Y	N	N 3/	N
Minnesota	Y	N	Y	N 2/	Y	N 3/
Mississippi	Y	Y	Y	N	Y	N
Missouri	Y	N	Y	N	Y	N
Montana	Y	Y	Y	Y	Y	Y
Nebraska 1/	N	N	N	N	N	N
Nevada	Y	N 1/	Y	N 2/	Y	N 3/
New Hampshire	Y	N	Y	N	Y	N
New Jersey	Y	N	Y	N	Y	N
New Mexico	Y	Y 1/	Y	Y 2/	Y	Y 3/
New York	Y	Y	Y	N	Y	Y
North Carolina	Y	N	Y	N	Y	N
North Dakota	Y	N	Y	N	Y	N
Ohio	Y	N	Y	N	N	N
Oklahoma	Y	N	Y	N	Y	N
Oregon	Y	N 1/	Y	N 2/	Y	N 3/
Pennsylvania	Y	Y 1/	Y	Y 2/	Y	Y 3/
Rhode Island	Y	Y	Y	Y	Y	Y
South Carolina	Y	N	Y	N	Y	N
South Dakota	Y	N	Y	Y	Y	N
Tennessee	Y	N	Y	N	Y	N
Texas	Y	Y	Y	Y	Y	Y
Utah	Y	N	Y	N	Y	N
Vermont	Y	Y	Y	Y	Y	Y
Virginia	Y	N	Y	N	Y	N
Washington	Y	N	Y	N	Y	N
West Virginia	Y	N	Y	Y	Y	Y
Wisconsin	Y	Y	Y	Y	N 3/	N 3/
Wyoming	Y	Y 1/	Y	Y 2/	Y	Y 3/

Source: Appendix Tables A-1, A-4, and A-5 of this report.

* For tables 1 and 2, a "Y" means that a state agency does have the described authority, and an "N" means that the state agency does not have the described authority.

1/ This response is qualified. The reader should refer to the footnotes in Appendix Table A-1 for the specific qualification to this response.

2/ This response is qualified. The reader should refer to the footnotes in Appendix Table A-4 for the specific qualification to this response.

3/ This response is qualified. The reader should refer to the footnotes in Appendix Table A-5 for the specific qualification to this response.

initiate investigations of the rates of both types of utilities, and (3) to suspend rate changes proposed by both types of utilities. The letters, "Y" and "N", in a column indicate that the state listed in the first column does (Y for yes) or does not (N for no) have the authority stated in the heading of that column. Certain explanations and limitations of states' authorities are given in the footnotes to the appendix tables.

All the states, except Nebraska, regulate rates for retail gas sales by privately-owned companies and can initiate rate investigations of such companies. The State of Nebraska does not regulate electric or gas utilities; such utilities are owned or regulated by public power districts and municipal governments. All but six states have authority to suspend a rate change that a privately-owned utility would put into effect.[1]

Thirteen states have significant ratemaking authority over publicly-owned companies. In other states, either there are no such companies (15 states), or state law exempts such companies, primarily municipal utilities, from state regulation.

Table 2 summarizes other important state authorities and other information with respect to the natural gas industry. The first four columns of table 2 deal with the regulatory authorities of the state utility commissions. Column 1 indicates that 44 commissions, including

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[1] Some care is required in interpreting these authorities. For example, all but six states can suspend privately-owned utility rate changes, but this does not mean that such utilities can unilaterally increase rates in six states. In Nebraska, utilities are not regulated by the state government. In Michigan and Wisconsin, the regulatory commissions are not specifically authorized to suspend utility rate increases because the utilities are specifically prohibited from attempting unilateral increases. Such additional detail is given in the footnotes of tables in the appendix.

TABLE 2

STATE AGENCY AUTHORITY CONCERNING SECURITY ISSUANCE, INTERCONNECTIONS, AND CONSTRUCTION; THE NUMBER OF GAS UTILITIES OPERATING BY STATE; AND COMPANY ABILITY TO REFUSE NEW SERVICE

Column Agency	(1) Authority to Require Approval Prior to Security Issuance 1/	(2) Authority to Authorize or Require Gas Interconnections by Private Companies 2/	(3) Authority to Authorize or Require Gas Interconnections by Public Companies 2/	(4) Authority to Require Certificates of Convenience and Necessity for Construction 3/	(5) Number of Gas Utilities Operating in Each State 4/	(6) Companies Can Refuse New Service if Gas is Available 5/
Alabama	Y	Y	N	Y	107	N
Alaska	N	Y	Y	Y	5	N
Arizona	Y	Y	N	N	15	N
Arkansas	Y	N	N	Y	22	Y 10/
California	Y	Y	N	N	10	N
Colorado	Y	Y	Y 7/	N	20	N
Connecticut	Y	N	N	Y	6	Y
Delaware	Y	Y	N	N	3	N
D.C.	Y	N	N	N	1	N 10/
Florida	Y	Y	N	N	125	Y
Georgia	Y	N	N	Y	93	Y
Hawaii	Y	N	N	N 8/	1	11/
Idaho	Y	N	N	Y	2	N
Illinois	Y	Y	N	Y	85	N
Indiana	Y	N	N	N	46	Y
Iowa	N	Y	Y	Y	52	N
Kansas	Y	Y	Y 7/	N	90	N
Kentucky	Y	Y	N	Y	90	N
Louisiana	Y	Y	N	N	139	Y 10/
Maine	Y	Y	Y	N	2	Y
Maryland	Y	Y	Y	N	11	Y 10/
Massachusetts	Y	Y	Y	Y	18	Y
Michigan	Y	Y	N 7/	Y	10	Y 10/
Minnesota	Y	N	N	N	29	N
Mississippi	N	Y	Y	Y	55	N
Missouri	Y	Y	N	Y	47	N
Montana	Y	N	N	N	15	N
Nebraska 6/	N	N	N	N	10 9/	N
Nevada	Y	N	N	Y	3	N
New Hampshire	Y	Y	N	N	7	N
New Jersey	Y	Y	Y 7/	Y	4	N
New Mexico	Y	Y	N	Y	16	N
New York	Y	Y	Y	Y	76	N
North Carolina	Y	Y	N	N	13	N
North Dakota	Y	Y	N	Y	9	N
Ohio	Y	Y	N	Y	28 9/	N
Oklahoma	N	Y	N	N	98	Y 10/
Oregon	Y	Y	Y	N	3	N
Pennsylvania	Y	N	N	Y	43	N
Rhode Island	Y	Y	N	Y	5	N
South Carolina	Y	Y	N	Y	21	Y 10/
South Dakota	Y	Y	N	N	5	Y
Tennessee	Y	N	N	Y	100	Y
Texas	N	Y	Y	N	409	N
Utah	Y	Y	N	Y	4	Y
Vermont	Y	Y	N 8/	Y	5	N
Virginia	Y	Y	N	Y	17	Y
Washington	Y	Y	Y	N	7	N
West Virginia	N	Y	Y	Y	41	N
Wisconsin	Y	Y	Y	Y	17	N
Wyoming	Y	Y	Y 7/	Y	22	N

Source: Appendix Tables A-6, A-9, A-10, A-12 and A-14 of this report.

1/ A commission's authority to require approval prior to the issuance of any new security such as a bond, stock, note or option is signified by a yes in column one. See Appendix Table A-6 for a detailed treatment of this topic by type of security.

2/ For a breakdown at which states have authority to authorize gas interconnections and which states have authority to require them, see Appendix Table A-9.

3/ See Appendix Table A-10 for a detailed examination of state agency authority to require certificates of convenience and necessity for various types of construction by private and publicly-owned gas companies.

4/ See Appendix Table A-12 for information on the number of privately-owned and publicly-owned gas utilities in each state.

5/ For additional information on state policy and company practices regarding the attachment of new gas customers and loads see Appendix Table A-14.

6/ This response is qualified. The reader should refer to the footnotes in Appendix Table A-6 for the specific qualification to this response.

7/ This response is qualified. The reader should refer to the footnotes in Appendix Table A-9 for the specific qualification to this response.

8/ This response is qualified. The reader should refer to the footnotes in Appendix Table A-10 for the specific qualification to this response.

9/ This response is qualified. The reader should refer to the footnotes in Appendix Table A-12 for the specific qualification to this response.

10/ This response is qaulified. The reader should refer to the footnotes in Appendix Table A-14 for the specific qualification to this repponse.

11/ Not available.

that of the District of Columbia, have authority to require gas utilities to obtain state agency approval prior to the issuance of at least one type of security. (Appendix table A-6 gives information on the various types of securities for which each state requires approval prior to issuance.)

The second and third columns of table 2 indicate those states that have authority to assure adequate gas service by authorizing or requiring gas interconnections among gas utilities. Thirty-eight states have authority to authorize or to require gas interconnection for investor-owned gas utilities as indicated in column 2. Sixteen states have authority to authorize or require gas interconnections for publicly-owned gas utilities; however, some of these states regulate municipal gas service only when it extends beyond the municipality's boundaries.

Twenty-nine state agencies have authority to require a gas utility to obtain a certificate of convenience and necessity before beginning any major new construction project.[1] (Appendix table A-10 shows each state utility commission's authority to require certificates of convenience and necessity for the construction of gas generating plant, gas transmission lines, gas distribution lines and other plant. These certification requirements are indicated separately for privately- and publicly-owned gas companies.)

The number of gas utilities in each state is given in column 5 of table 2. The number of gas utilities in each state ranges from one gas utility in Hawaii and the District of Columbia to 409 gas utilities in Texas. The average number of gas utilities is 39 per state. There are five states (Alabama, Florida, Louisiana, Tennessee, and Texas) with 100 or more gas utilities. Seven states have between 50 and 99 gas utilities. Four states have 30 to 49 gas utilities. Eighteen states have 10 to 29 gas utilities, and seventeen states have 9 or fewer gas utilities. These figures include the number of both privately-owned and publicly-owned gas utilities in each state, except for Nebraska and Ohio where some information was unavailable.

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[1] Although Hawaii does not use certificates of convenience and necessity, the Hawaii Public Utilities Commission reviews any proposed investment in plant and equipment that amounts to more than a half-million dollars or is ten percent or more of total plant in service.

The last column in table 2 indicates that in fifteen states gas companies can refuse service when gas is available. Arkansas and Oklahoma limit gas company discretion in refusing new business by restricting refusals of service to cases where unreasonable costs are involved, such as when a distribution pipeline must be extended into a remote area. Louisiana and Maryland allow a refusal of service when it complies with the distribution company's extension plan. In Michigan, the Public Service Commission must authorize any refusal of service. In South Carolina, company discretion in refusing service is subject to being overruled by the commission. The District of Columbia gas utility may refuse service for such reasons as the excessive cost of the service line but not because of the cost of the gas itself.

Major Issues and Problems of State Regulators

In this section, the major issues and problems currently faced by states regulators of the gas distribution utilities are identified and discussed. For the most part, these issues are ratemaking issues. At present, securities issuance, pipeline safety, and other areas do not represent areas of significant difficulty. At the 93rd Annual Convention of the National Association of Regulatory Utility Commissioners (NARUC), two ratemaking issues in particular were forcefully debated by the NARUC Committee on Gas on November 17, 1981. Both related to State commission "rubber stamping" of certain Federal decisions: one related to take-or-pay contracts and the other to the Alaska Natural Gas Transportation System (ANGTS).

Contracts for gas supply between producers and interstate pipelines are often on a take-or-pay basis, that is, the pipeline agrees to buy at a certain fraction of the maximum contract amount or to pay for that fraction even if it does not actually take the gas. Normally, there is both an annual and a daily purchase obligation. The Committee on Gas received a written subcommittee report on take or pay contracts, discussed certain factual questions, and debated the value of the use of such contracts. It was asserted by some that many "new" gas contracts (gas contracts signed after passage of the Natural Gas Policy Act of 1978, NGPA) contain an unusually high take-or-pay clause percentage, requiring pipelines to buy 90 to 95% of the maximum contract amount, and that this contrasts with a historically lower figures of 75% or so. It was further asserted that the rapid rise in retail gas rates is, in part, due to the use of take-or-pay provisions: new gas is more costly and has more rapid price increases, but when demand for gas drops the lower cost "old" gas under a 75% provision is curtailed ahead of higher cost "new" gas under a 95% provision. Some contended that accelerated deregulation of well-head prices would exacerbate this effect.

Because these contracts are between producers and pipelines, the high cost gas is passed along to the distribution companies, which may in turn have take-or-pay contracts with the pipeline companies. Distribution companies--and the state agencies that regulate them--would like to have disclosure of the terms of the producer-pipeline contracts, including the take-or-pay provisions and the price escalation provisions. But, because the pipelines are regulated by the Federal Energy Regulatory Commission (FERC) which does not require such disclosure, States feel required to pass along the resulting gas cost increases, without State review, in distribution company rates.

States may also be required to pass along pipeline capacity costs for ANGTS without review. According to its sponsors and the major banks arranging financing, the 4800-mile pipeline system for carrying gas from the North Slope of Alaska cannot be privately financed unless certain normal requirements of law and regulatory practice are waived by the Federal government. The most difficult waiver for some state regulators is one to allow the FERC to include in the rates of the sponsoring pipeline companies the costs of sections of ANGTS as they are completed. The result would be to "pre-bill" customers for the costs of ANGTS, years before the gas flows. Many state regulatory agencies believe that such a ratemaking practice is contrary to state law, which typically requires that the agency find a facility to be "used and useful" before allowing it in rates. However, it appears that after the FERC has approved a rate charged by a pipeline, the due-process clause of the Fourteenth Amendment and the Supremacy Clause would preclude any state action that would prevent recovery of ANGTS costs from distribution company customers.

While these two ratemaking issues are of great concern to state regulators, they may be problems beyond state control. The ratemaking issues currently of importance that are within state control are the following:

1. Whether to use marginal or embedded costs for ratemaking purposes.
2. Whether to institute a lifeline rate either for the poor or for all low volume users.
3. Whether to have declining block rates, flat rates, or inverted rates.
4. Whether purchased gas adjustment clauses are properly designed and monitored.

An elaboration of each of these issues follows.

Marginal versus Embedded Costs. - There are two distinct methodologies for determining the cost of gas distribution service: the allocation of embedded cost and the calculation of marginal cost. Within either methodology there can be several methods for determining the cost of service. Advocates of the two approaches differ on what it is that should be calculated: they differ regarding the meaning of the word "cost."

In traditional cost accounting, the total costs experienced by the utility during a historical test year (embedded costs) are allocated among the various categories of service offered by the utility. Some costs are easily allocable. For example, the cost of large recording meters is allocated to the industrial class of customers because only such customers use these meters. Other costs, such as the cost of administration, are for the benefit of all customers and must be allocated according to traditionally accepted methods of cost accounting. Differences regarding which method to use for the allocation of these common costs underlie different espoused methods for traditional cost-of-service studies.

Proponents of embedded cost ratemaking advance several reasons for continuing this practice. First and foremost, such costs are familiar to both utilities and utility commissions, having evolved as a nationally accepted approach during the history of gas distribution regulation.

Second, proponents claim that the issues relating to embedded cost methods are clearer, easier to understand, and more suited to the administrative procedures that characterize a gas distribution rate case than the issues involved in marginal cost ratemaking. The use of a historic test year negates any need for difficult analysis concerning forecasting methodologies to determine costs in a projected test year. In particular, it avoids the calculation of system expansion costs, which may be required in a marginal cost calculation. Also avoided is the issue of how to adjust marginal-cost-based rates to generate the required revenues. Because embedded cost issues are clearer and precedents have often been established on how to resolve them, these issues will be more easily and expediously resolved.

Third, embedded costs are said to provide reasonable estimates of the cost responsibility of each class of gas customer and are easily adaptable, by altering the allocation procedure, to changing utility and regulatory concerns.

From the economist's viewpoint, costs calculated in this way have no meaning. There is no theoretically correct way to allocate common costs.

The allocated cost of serving an individual (customer or class of customer) is a fictitious number that should have no relation to the price of the service, in economic theory.

The economist views the cost of serving an individual as the amount of cost-savings the utility would realize if it did not serve him. It is the reduction in total costs by removing him from the distribution system. Stated another way, it is the additional cost of adding to the system another customer with the same usage characteristics as the customer in question. This additional cost is called the marginal cost for the customer. Economists contend that the marginal costs are the proper basis for setting rates.

The principle argument in favor of marginal cost ratemaking is that it promotes "economic efficiency." That is, it encourages the best use of society's resources (labor, capital, land, fuels, and so on). The idea is that prices, either low or high, induce customers to consume either more or less natural gas (and, with their remaining dollars, more or less of other goods and services). With gas prices equal to marginal costs, customers are induced to consume the "right" amount of gas because the value placed by each customer on additional gas consumption just equals the value he places on additional consumption of other goods (assuming other goods are priced at their marginal costs also). If gas rates are unequal to marginal costs, customers will consume too little or too much gas--inducing utilities to over- or under-invest in natural gas distribution.

A difficulty with setting prices equal to marginal costs is that the resulting annual revenues may be either too much (yielding an excess profit) or too little (threatening the utility's ability to continue service). State regulatory agencies traditionally determine an annual "revenue requirement" that covers costs and allows for a fair return on investments in the utility. Rates based on embedded costs are designed by an allocation procedure to be, in some sense, fair but primarily to yield the annual revenue requirement target. But, gas rates set equal to marginal costs would most likely generate revenues in excess of the revenue requirement. The excess revenue problem flows from marginal cost calculations being based on projected future costs while revenue requirements are determined from existing and past embedded costs. Therefore, the revenues generated by marginal cost rates tend to exceed the revenue requirement when costs are rising. The opposite would be true when costs are falling. Most advocates of marginal cost pricing concede that rates should be allowed to deviate from marginal costs just enough so that the revenue requirement is attained. However, this leads to arbitrary methods of shedding excess revenues.

Another difficulty with marginal cost rates is that economic efficiency is assured only when products other than gas are also priced at their marginal costs. In brief, the argument is that in order to achieve efficiency through pricing policy, marginal costs must also to be reflected in the prices of substitutes (electricity and oil, for example), the prices of complements (gas furnaces), the prices of inputs (gas pipes and compressors), and even the prices of products requiring gas for their own production (fertilizer). In the absence of such prices, economists cannot predict whether marginal cost pricing for gas distribution service would increase economic efficiency. (Economists call this situation, the "second best" problem.) If the price of gas received by the distribution company is not set at marginal cost by the FERC, the usefulness of setting distribution company rates at marginal costs is unknown.

A final difficulty with marginal cost rates for gas is that in changing over to a new ratemaking approach there will be winners and losers: bills will increase for some customers and classes of customers and decrease for others. Some critics of marginal cost pricing contend that its real purpose is to lower residential rates at the expense of industrial customers.

The effect of Federal legislation on State consideration of this issue is discussed later in this chapter.

Lifeline Rates. - Lifeline rates are often thought of as the same as inverted rates, which are discussed in the next subsection. In this report, lifeline rates are considered quite distinct, even though lifeline rate structures are almost always inverted. A lifeline rate is a social rate design that has as its goal the furnishing of a quantity of gas sufficient to meet the basic energy needs of residential customers at an admittedly subsidized cost. If it is intended to cover space heating needs, the quantity of gas covered by the low rate would vary according to geographical location and season of the year. It is usually agreed that the lifeline rate should not be less than the distribution utility's variable cost, principally the cost it pays to its supplier for the gas. The rate may cover a portion of the utility's fixed plant costs, depending on the amount of the subsidy. The costs not covered by the lifeline rate are spread over the rates of other customers, either the high-use residential customers only or all other customers including commercial and industrial. In theory, state government could cover the subsidized costs, but in practice government subsidized energy use is not implemented through a lifeline rate program.

Advocates of lifeline rates contend that the practice is desirable because it avoids the administrative costs of direct government aid, such as welfare or energy stamps. Also, lifeline rates for all, or just poor, residential customers enable the recipients to receive essential aid without the demeaning aspects of visiting a welfare agency.

Critics of lifeline rates contend that the program is based on the assumption that most low-volume residential users are poor and most high-volume users are not--and that the assumption is often untrue. Wealthy customers may qualify for lifeline rates for their low-use vacation cottage, while large, poor families in large homes and elderly customers in older, poorly insulated homes are high-volume users that must cover not only high gas costs but also the lifeline subsidy. Even when customers must be "certified" as poor to qualify for lifeline, opponents contend that the administrative costs are then large.

Whether lifeline is for all residential customers or just the poor, critics contend that the program is opposed to economic efficiency and that the harm done by price distortion is not balanced by the benefits received. Most economists believe that, if a subsidy is necessary, it should come as an income supplement rather than as a gas price reduction. The supplement allows the recipient the freedom of choice to use the extra income to pay for natural gas, to pay for insulation, to buy warmer clothing, or by conserving gas to direct the funds to his or her own higher priority needs.

Rate Structure. - A current issue before many state regulatory agencies is whether the structure of natural gas rates should be declining, flat, or inverted. Declining block rates are designed so that prices decline with increasing consumption. For example, the following is a declining block rate: $5 per thousand cubic feet of gas (i.e., per MCF) for the first 4 or less MCF: $4 per MCF for the next 6 MCF (i.e., up to 10 MCF); and $3 for all additional consumption. Each downward step is called a rate block; some tariffs may have many blocks. The declining block rate for natural gas distribution utilities evolved from earlier rate forms in the first few decades of this century and was the most commonly used rate form through the 1970's.

While most utilities still defend the declining block rate, various customer groups champion either flat or inverted rates. A flat rate is a single price (e.g., $3.25 per MCF) that does not depend on the level of consumption; it is usually used together with a fixed customer charge, also independent of usage (e.g., a customer charge of $4 per month plus a flat rate of $3.25 per MCF). Inverted rates are designed so that prices increase with increasing consumption, as if the traditional declining block rate were inverted.

Utilities, and others, defend declining block rates on the grounds that they reflect declining service costs. A utility incurs certain fixed costs in serving a customer, primarily for pumps and pipeline capacity, regardless of the customer's gas usage level, and the initial rate blocks are intended to recover not only the variable cost of gas but also the customer's share of these fixed costs. Occasionally, utilities have argued that the load of large use customers is steadier, less variable, than low use customers, so that as energy use increases a declining fixed-cost surcharge is appropriate.

Opponents of declining block rates assert that the rate is primarily a promotional tool. In the early days of the industry, when the cost of supplying gas was low and gas was abundant, utilities realized that they could achieve economies of scale if they could continue to expand the size of their facilities. To promote growth in gas sales, declining block prices were instituted. Critics contend that this may have been economically justified when gas was abundant, but that it is inappropriate today.

Instead, some argue that flat rates are now the most appropriate, with certain fixed costs covered by the fixed customer charge. During the late 1970's, there has been a trend to "flatten" gas rates in most states; that is, to reduce the number of rate blocks and the price differences between blocks--or to institute a true flat rate.

Where rates have been flattened, the size of the customer charge is usually an issue. On the one hand, some argue that most fixed costs should be included in the customer charge so that the flat rate would cover little more than the utility's cost of gas from its supplier. This approach, on the other hand, results in a large gas bill--on a dollar per MCF basis--for small users. Hence, some consumer advocates may argue for spreading more of the fixed costs over the flat rate portion of the tariff.

Still others argue for an inverted rate. With an inverted rate, the last block is set at a price above the average cost of service, possibly at marginal cost. Price for the initial block is below average, possibly chosen so as to meet the revenue requirement of the company. Inverted rates are generally designed to encourage conservation of natural gas. Such rates are not admitted surcharges or subsidies, but are asserted to be based on the cost of service using a variant of marginal cost pricing principles. Supporters of inverted rates cite economic efficiency and low-rates-for-low-volume-users as secondary advantages of this rate scheme.

However, many economists reject the notion that price should vary with an individual's level of consumption. Some lifeline supporters, who believe that aid should be targeted to the poor, do not support inverted rates. Such rates are usually opposed also by large commercial and industrial customers who claim that inverted rates are an attempt to shift more of the fixed costs of the gas distribution system from residential to other tariffs. In addition, it is difficult to demonstrate that conservation will result, i.e., that the effect of the rate increase in later rate blocks will not be offset by the effect of the rate decrease in the early blocks. Furthermore, utilities usually oppose this rate structure because it increases the annual fluctuation in revenues. Much of the winter gas usage is sold at the price of the last rate block. If the price is high, during a severe winter the utility would receive an unusually high level of revenues, but during a mild winter the revenues may be insufficient to meet all current obligations.

For these reasons, the inverted rate has not been adopted to any great extent.

Purchased Gas Adjustment Clauses. - Purchased gas adjustment clauses for natural gas, like fuel adjustment clauses for electric service, are a vehicle for passing through to customers increases in energy costs faced by a regulated utility, without having a full rate case hearing to decide the issue. Most natural gas distribution utilities purchase all or most of their gas from a producer or a transmission company. The price of gas is typically specified under long-term contract with an escalator clause that permits the supplier to pass along his own cost increases to the distribution company. Many regulators believe that it is unreasonable to have a lengthy and costly rate case, which involves re-examination of all the company's costs and asset values, whenever one known cost, that of the gas itself, changes--especially during a period of frequent gas price increases.

Several issues are faced by state regulatory agencies regarding purchased gas adjustment clauses (PGA's). One is whether there should be a PGA at all. Opponents of PGA's contend that they are antithetical to good regulation. Traditionally, utility rates were in effect for several years at a time, and the ability of utility management to control cost increases--or to reduce costs--determined the profitability of the company during those years. This "regulatory lag" between the incurrence of a cost increase or decrease and its reflection in new rates of the monopoly utility is the regulatory substitute for the competition of the marketplace. Opponents of PGA's contend that PGA's reduce the motivation of utility management to hold down costs aggressively.

Another PGA issue is to what degree the cost pass-through should be automatic. In some cases, the utility is permitted simply to raise rates. But, totally automatic clauses are uncommon. In most cases, the utility is authorized to pass on increased costs, but is subject to having the increase in rates reviewed by the regulatory agency and suspended prior to actual implementation. In a few cases, hearings are required periodically to sanction the cost pass-through, and such hearings can take on the character of a mini-rate case focussing on gas costs.

Still another issue faced by the states concerns what costs to include in the PGA calculation. The adjustment may be based on costs actually experienced in the recent past or projected costs for the period when the PGA rate is to be in effect. The adjustment may cover all or a portion of increased costs; it may include or exclude gas from utility-owned wells; and it may account for gas withdrawn from storage on the basis of different accounting principles (LIFO, FIFO, other).

The PGA's adopted across the nation may differ greatly in detail, even though they are designed to accomplish the same basic goal. This variety leads to a variety of issues that may be state-specific or even utility specific: the treatment of the over-recovery of gas costs, when rate changes are reflected in customers bills, what percentage of adjustment is allowed without hearings, for what maximum time limit may an adjusted rate be maintained before hearings are required.

In addition to the design and operation of the PGA, state agencies face the issue of what level of monitoring of the utility by the agency is required to ensure that management is reasonably aggressive in looking for the lowest cost gas suppliers, engaging in contracts with escalator clauses favorable to ratepayers, and accurately reporting costs. Among the monitoring activities that the state agency may undertake are the following:

1. Reporting. Uniform reporting of key cost, revenue and operating data may be required for each adjustment.

2. Review. A review of each set of reported data by the staff of the state agency may be needed to ensure completeness of reporting, to test the correctness of the company's calculational method and arithmetic, and to compare the result with that expected from comparison with other periods or other utilities.
3. Audit. Periodically, the agency staff may conduct an in-depth audit of the gas acquisition practices of the company, including financial and operating practices.
4. Hearing. Subsequent to the audit a formal gas cost hearing before the commission may be required.

Each of these four monitoring activities may be undertaken or not by the state agency observing a utility with a PGA, and each activity may be carried out with various degrees of thoroughness. An issue faced by state agencies is to choose the appropriate level of each activity--to decide whether additional monitoring costs yield compensating ratepayer benefits.

Other Issues. - In addition to these current ratemaking issues, it is worthwhile to consider a major problem of the recent past faced by state utility regulatory agencies: the allocation of gas under supply curtailment. If gas supplies should decline in the future, similar issues will emerge again.

During the early and middle 1970's, the demand for interstate natural gas by the consuming states exceeded the available interstate supply. There was relatively little that state agencies in the consuming states could do to increase supply--control of supply was, in part, in federal hands--but states were faced with the difficulty of allocating the limited supply.

In most states, the first response was to impose restrictions on hooking up new customers to the system in order to limit the growth in demand and protect supplies for existing customers. The next step was relatively easy--to ban the use of gas as a fuel in large boilers that had alternate fuel capability. Next came smaller boilers of commercial and industrial customers with alternate fuel capability, and this led to several issues. In general, there was no good data on which customers had alternate fuel capability. Schools, hospitals, libraries, and other public service institutions often were billed under the "commercial" tariff, and requested special allocations from the state agencies.

After boiler curtailments, curtailments were generally according to a priority scheme that had to be devised by each state. During the early 1970's, the Federal Power Commission, FPC, (now the FERC) had the authority to determine how the curtailment burden of a transmission company should be distributed among the distribution utilities served by that transmission company. The FPC chose a scheme based on the customer characteristics of the distribution companies. However, once a distribution company received the gas under this scheme, the state agency was free to implement its own allocation plan for dispensing the gas received.

In addition to the issue of who received gas, two other issues emerged that were related to curtailments. First was the issue of how to treat any high-priced gas that became available to alleviate curtailments: on the basis of "roll-in" pricing or on the basis of "incremental" pricing. In the first case, the cost of the additional gas was averaged in (rolled in) with low cost of the bulk of the supply--so that every customer's rate increased slightly. In the second case, certain curtailed customers were allowed to receive the gas only if they would bear the full extra (incremental) cost of new supplies. Different states adopted different approaches, but the decisions involved considerable controversy.

The second issue related to curtailments involved how to cover the fixed costs of excess distribution pipeline capacity. Under the traditional ratemaking formula, the annual revenue requirement of a utility is composed of a fixed and a variable portion. The average price of gas is simply the quotient of the revenue requirement divided by the volume of gas sold. As the volume is curtailed, the variable portion of the revenue requirement (primarily, the cost of gas) decreases, but the fixed portion (the cost of fixed system) remains constant. As a result, the average price of gas increases as the supply decreases.

Some states instituted a "curtailment tracking adjustment clause" or a "volumetric variation adjustment" to rates, which permitted a utility to raise its rates so that supply curtailments would not lead to revenue losses and to inability to satisfy company stockholders or even bondholders. Consumer groups were outraged that some state agencies were permitting price hikes during a period of declining quality of service by the gas industry. They raised the question of whether the industry should be "held harmless" during a period of poor supply performance.

This issue was, perhaps, never satisfactorily resolved, but simply faded away along with the need for curtailments. It may re-emerge, however, during the 1980's if either supplies are curtailed or, more likely, some existing customers leave the system because gas prices rise faster than the price of alternate fuels. Then, customers "locked in" to gas may raise this issue again.

Recent activities. - Three recent activities of state regulators of natural gas distribution companies should be mentioned, not because they involved major policy issues in most states, but simply because they have taken a great deal of regulators' time recently. Each was mandated by the National Energy Act (1978). They are (1) conducting hearings on the PURPA standard regarding the elimination of master metering in residential buildings, (2) conducting hearings on the PURPA standard regarding the establishment of customer disconnect policies, and (3) establishing rules, as required by the Fuel Use Act, relating to a ban on outdoor decorative gas lighting.

Monopoly Characteristics and Behavior

Public utility regulation by controlling the entry of new gas distributors in a service territory supplants competition among gas distributors. The primary tools of the public utility commission and local authorities for limiting competition are the market franchise and the certificate of convenience and necessity. By controlling entry, two policy objectives are facilitated. First, the benefits of economies of scale can be realized or the wastes of competition can be avoided by having a gas distributor who serves the franchised market area be a monopolist. Second, restrictions on entry effectively control investment in distribution facilities. This control enhances the commission's ability to regulate prices and profits for a gas distributor.

The validity of the policy of having a monopoly for gas distribution in a given market area depends on several technological factors. The physical connection between the distributor's point of supply and the consumers' premises is a feature unique to utilities that has several substantive consequences. First, de nova entry into natural gas distribution or expansion of facilities is characterized by indivisibilities. Second, once this investment in a distribution system is made, the resources are sunk and relatively immobile. Third, rights of way must be acquired and maintained. Finally, the physical connection creates conditions favorable to the practice of price discrimination. Each of these consequences of the physical connection can lead to costly or wasteful competition or impose undue burdens on the consumers if competition were allowed. In conjunction with the consequences of the physical connection, economies of scale are the most often advanced rationale for monopoly in the provision of natural gas distribution services. According to this concept, one distributor can supply distribution services to the market at a lower cost than two or more distributors. Monopoly is considered to be the natural outcome of market forces in these circumstances. Public utility regulation by establishing monopoly and supplanting competition avoids the wastes and undue burdens of an unregulated market.

In this section, the rationale for monopoly in the provision of distribution services and the feasibility of intraproduct and interproduct competition are examined. The section is divided into seven parts. The use of the franchise, the certificate of convenience and necessity, and anti-piracy laws is examined in the first part. In the second part, the competitive implications of the physical connection between the distributor and the consumers are covered. A theoretical and empirical investigation of economies of scale is presented in the third part of the section. The fourth part contains a discussion of rights of way as a scarce community resource. In the fifth part, the possibilities for price discrimination are examined. The role of vertical integration in dampening competitive forces and in complicating the regulation of prices and profits is examined in the sixth part. Finally, the potential for intraproduct and interproduct competition is addressed. Particular attention is given to the performance problems attributable to existing and potential structure and behavioral problems.

Legal Barriers to Intraproduct Competition

Three general steps are required for a utility to enter a market. They are the corporate charter, the franchise, and the certificate of convenience and necessity. As mentioned, the franchise and the certificate are legal methods by which the state and local authorities can control entry into a market. Supplementing these controls in many states are statutes, agreements, or case law that prevent competition among gas distributors in a market area. These controls on entry are discussed below.

The franchise is an ordinance or a contract specifying the conditions under which a utility provides service to a given area. Franchises are necessary because a utility in most cases cannot render service without using city streets and thoroughfares. The franchise constitutes permission for the utility to use its streets. It can be an exclusive franchise. In this case, the utility becomes the sole supplier of the service to the locality. In turn, the utility must give some assurance of reasonable service quality and rates, as well as provide some services to the city at favorable rates. Without the grant of a franchise, a firm seeking to render the utility's service would be illegally using the city's streets and thoroughfares.

The certificate of convenience and necessity is an equally potent legal barrier to entry if state authorities use it in this way. The certificate is obtained from state public utility commissions. The application by the potential entrant must demonstrate that its facilities are needed, and that it, as a utility, could provide adequate service at a reasonable price. To accomplish this, the applicant must submit the plans of its proposed facility, show that it would meet minimum quality and performance standards, submit the estimated cost of construction and operating expenses, present a financial strategy to raise necessary funds, and file a proposed set of rates for rendering service. The issuance of a certificate of convenience and necessity authorizes the construction to proceed and also defines the service area.

Both state and local authorities as a matter of policy could authorize more than one utililty to render service in a specific area. This is not done in the belief that a regulated monopoly can render service at a lower social cost per unit of gas delivered than can two or more firms in competition. This policy is supported by agreements, federal and state regulatory commission decisions, federal and state court decisions, and statutes. The general rationale focuses on the wastes of competition associated with duplicate facilities. Several examples are given below.

The Montanta Public Service Commission asserted in the case, Montana Public Service Commission v Blue Flame Gas Co. (Mon) PUR 1926D 314, 319, that competition is not in all circumstances the best protector of the public interest. It stated:

> ...(I)t has been conclusively demonstrated in almost every small community where the experiment was to be tried that the grant of franchises to competing public utilities is wrong in principle and invariably results in unsatisfactory service. Competition has long ceased to be potent as a regulatory factor in public utility operations. Where it was relied upon, it proved to be bad in the long run for consumers of utility service, as too often it meant duplication of facilities in a field not large enough to support more than one company. The usual outcome of this was consolidation, followed by recoupment, by means of higher rates, of losses due to competition.

This opinion by the Montana commission suggests that the validity of a monopoly might be limited by the size of the relevant market. However, competition is deemed bad for both consumers and investors. Destructive competition destroys the value of investments in plant and equipment. Investors lose money and become leery of investing in a competitive utility industry. Consumers lose because the increased risks drive up costs, result in inferior and unreliable service, and eventually drive up rates.

At the federal and state level, the distinction between areas of commerce in which monopoly is appropriate and competition is inappropriate has been made several times. Judge Prettyman of the United States Court of Appeals for the District of Columbia distinguishes public utilities from other businesses. In the case of People of California v Federal Power Commission (1961) 111 US App DC 226, 42 PUR3d 288,295, 296 F2d 348,353, 354, Judge Prettyman writes

> Public utilities are treated as public services. The principle requirement is service, and service is not a necessary result of competition bent on mutual destruction.... The antitrust laws and the regulatory laws are not in conflict; they are complementary. Both have as their objective the public interest.

Regulated monopoly in the provision of utility services can supplant the marketplace and serve the public interest.

In the case City Gas Co v Peoples Gas System Inc. Fl Supr Crt (1965) 62 PUR3d 518, 182 So2d 429, Judge O'Connell writing for the Florida Supreme Court upheld an agreement between two gas companies with contiguous service areas that forbade competition and specified the markets that each could serve. Previously, both gas distributors had serviced a common area in competition with each other. The agreement was approved by the Florida Public Service Commission. When City Gas company violated ths agreement, a series of cases was initiated. This agreement was upheld, found not to be in conflict with the antitrust statues, and held to be in the public interest. The Florida Supreme Court's decision rested on the implied power of the commission to fix service territories through its issuance of the certificate of convenience and necessity.

Each of the decisions sets public utility service apart from other businesses. Public utilities provide services where reliable, high quality service is paramount to the public interest. Competition is viewed as wasteful, destructive, and not in the public interest. Instead, protected markets coupled with price and profit regulation is held to be conducive to low-cost, reliable service. State public utility commissions can protect the public interest by restricting entry and regulating prices and profits. The wisdom of using regulated monopoly to provide natural gas distribution services depends on several technological factor that preclude competition. It is to these considerations attention is now turned.

Monopoly, Technology, and High Investments Costs

Natural gas distribution entails the delivery of natural gas from a city gate to consumers at a pressure compatible with their end-use appliances. The distributor's plant, equipment, and structures primarily consist of a system of transmission, trunk, feeder, and distribution mains which transport gas at various pressure levels. The investment in mains is characterized by the indivisibility of certain costs. An indivisibility occurs when a cost is incurred irrespective of the capacity or output of a facility installed. For example, the cost of digging a trench is the same no matter what size pipe is placed in the trench. As a result, distributors have an incentive to install extra, unused capacity. In addition, distribution is capital intensive and resources, once committed, are sunk and relatively immobile. Thus, very little of the investment can be recovered in uses other than natural gas distribution. Each of these characteristics of natural gas distribution is closely related to the fact a physical connection exists between the distributor's supply point and the consumer. The implications of this for monopoly or competition are examined in this section.

The costs of constructing a one-mile segment of distribution mains can be broken down into several cost components. Each of the components can be categorized by the unit of measurement by which the costs are incurred. This information is presented in table 3. Costs can be incurred by the ton, the inch-diameter per mile, and the mile. A substantial portion of the first investment costs for a segment of main is incurred on a per-mile basis. As such, these costs do not vary with the installed capacity of the main; they are indivisible. In particular, most of the costs of acquiring

TABLE 3

UNITS OF MEASUREMENT BY WHICH COSTS ARE INCURRED WHEN CONSTRUCTING A SEGMENT OF DISTRIBUTION MAINS, BY COST COMPONENT

Column Cost Component	(1) Dollars per Mile	(2) Dollars per Inch-Diameter Mile	(3) Dollars per Ton
Engineering and Survey	x		
Cost of Pipe		x	x
Freight			x
Laying Costs	x	x	
Valves, Flanges, Bolts, Welding Rod		x	
Inspection and Supervision	x	x	
Painting and Wrapping	x	x	
Rights of Way and Damages	x	x	

Source: Gas Engineers Handbook, The Industrial Press, 1966.

the rights of way, doing the engineering and survey work, and laying the mains are incurred on a per-mile basis. Laying costs weigh heavily into the cost of distribution mains. The laying costs include the costs of clearing and ditching the land, laying and welding the pipe, and backfilling and restoring the land. In most cases, a minimum of 50% of the first investment cost is independent of the capacity of the distribution mains.

This indivisibility of a major portion of the first investment costs creates an incentive for distributors to install unused capacity.[1] As a monopolist, the distributor can rationally anticipate the amount of unused capacity to hold for future use. This amount depends on the present value of installing more capacity in the future. The relevant time period depends on the growth rate of the coincident peak hourly demand along the segment of main. This planning is facilitated by the fact that the distributor, as a monoplist, serves all incremental demands along this segment of the distribution system.

In a competitive situation with two or more distributors serving an area, this indivisibility of investment costs can lead to a condition of chronic excess capacity. In these circumstances, competition can be destructive and cutthroat. This contention is discussed more fully below.

Natural gas distribution is a capital intensive business. A measure of this intensity is the capital turnover ratio. This ratio tells one the gross revenues generated by a dollar of investment in plant, equipment, and structures. The capital turnover ratio for natural gas distributors for 1977 was 0.95.[1] This compares to a capital turnover ratio of 2.0 for most manufacturing activities. Thus, a dollar invested in distribution facilities will generate less than a dollar in revenues; while a dollar invested in manufacturing will, on average, generate two dollars in revenues.

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[1] This incentive is not related to the Averch-Johnson effect. It is a technological phenomenon.

Compounding the commitment of a large investment in facilities is the fact that these resources are highly specialized and immobile. Once committed, the pipes, valves, gauges, services, and meters have little, if any, alternate uses. Furthermore, the removal of mains from a community is costly and impractical. Thus, investors must not only commit a large amount of funds, they must be assured that the risks of committing their resources to gas distribution are adequately compensated.

With the indivisibility of investment costs, capital intensive operations, and specialized, immobile resources, natural gas distribution has the conditions conducive to destructive competition. Destructive competition is a competitive situation in which all firms in an industry experience below-normal profits and declining quality of service. The major prerequistes for destructive competition are long sustained periods of excess capacity and investment costs that are a large percentage of total cost. Another necessary ingredient is independent competitive behavior by all firms in the industry. Such an industry would have a record of instability for prices and producer incomes. One prominent market imperfection leading to this result is the inability of capital to move out of a situation of excess capacity.[1] Thus, the period of excess capacity is prolonged during which the rate of return to firms remains below normal.

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[1] Calculated from information available in the American Gas Association, 1977 Gas Facts, Arlington, VA, the American Gas Assocation, 1978.

Even though natural gas distribution has many of the characteristics that lead to destructive competition, other characteristics, which may or may not apply to individual distribution companies, are also important to consider. In particular, independent behavior on the part of distributors is not necessarily guaranteed. Furthermore, the decisions that lead to excess capacity for the industry are conscious decisions by each distributor to install unused capacity. In evaluating whether these conditions would be met in a competitive gas distribution market, one can only speculate. The market that the industry serves in this case is either a community or contiguous set of communities. This geographical proximity of competitors lessens the potential for independent action. For a conclusive determination, one must, at least, assess the minimum optimal scale for a distributor. Independent action requires numerous competitors. If a market can only support few gas distributors, the competition in all likelihood would gravitate toward oligopoly or collusive monopoly. However, a period of destructive competition may be necessary before the distributors would coalesce.

In summary, the technology of natural gas distribution creates conditions similar to those associated with destructive competition. The physical connection between the consumer and producer has substantive implications. Some of the investment costs are indivisible. This creates incentives to install unused capacity. In addition, the technology of distribution is capital intense and the resources once committed have few alternate uses. These circumstances are the prerequisites for destructive competition except for one. Independent action requires numerous competitors. The number of distributors a community can support depends on the minimum optimal scale of a distribution system. Unfortunately, no empirical studies have investigated this scale of operation.

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[1] An assumption of the theory of perfect competition is the perfect, instantaneous mobility of all resources in the long run.

Economies of Scale and Natural Monopoly

Natural gas distribution is often considered a natural monopoly. Accordingly, one distributor can serve a market area at a lower social cost than can two or more suppliers because of economies of scale. Duplicative investments are wasteful, and monopoly is the outcome of natural market forces. Substantial economies of scale preclude any other outcome. Thus, public utility commissions act in the public interest by limiting entry and controlling prices and profits.

The validity of viewing natural gas distributors as natural monopolies depends on the extent to which economies of scale are in fact present in distribution. Economies of scale refer to the reduction in the total social cost per unit of output attributable to expanding the production capacity of an entity. The use of the term "entity" in this context indicates that economies of scale can occur at different levels of aggregation. Economies can be plant specific, product specific, or multiplant (system wide) economies. The plant of a gas distributor is defined for purpose of this paper as the system of mains from a community's city gate to the customers' premises. Plant-specific economies are the reductions in the average cost of delivering volume of gas as the capacity of the community's system expands. A multiplant operation is a distributor who financially and operationally integrates the distribution services for two or more communities under a single corporate charter. Multiplant economies are the reductions in the average total cost of delivering a volume of gas as the aggregate capacity of the company's system expands. The product of a natural gas distributor is the delivery of gas to an end-use appliance. For purpose of this discussion, the delivery of gas to a residential customer is a different product than delivery to a nonresidential consumer. Product-specific economies refer to the reductions in the average total cost of delivering a volume of gas to one customer class as the capacity to deliver gas to that class expands. This framework is the basis for discussing and analyzing economies of scale in natural gas distribution.

The discussion and analysis here (though not necessarily the conclusions) draws heavily upon the empirical investigation of statistical cost functions for natural gas distribution by Dr. Jean-Michel Guldmann.[1] He has developed statistical cost functions for various expense and investment accounts for natural gas distributors at the community and company level.

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[1] Chapters 3 and 4 of J-M Guldmann, R. Tybout, and William Pollard, Marginal Cost Pricing for Natural Gas Distribution, The National Regulatory Research Institute, 1981.

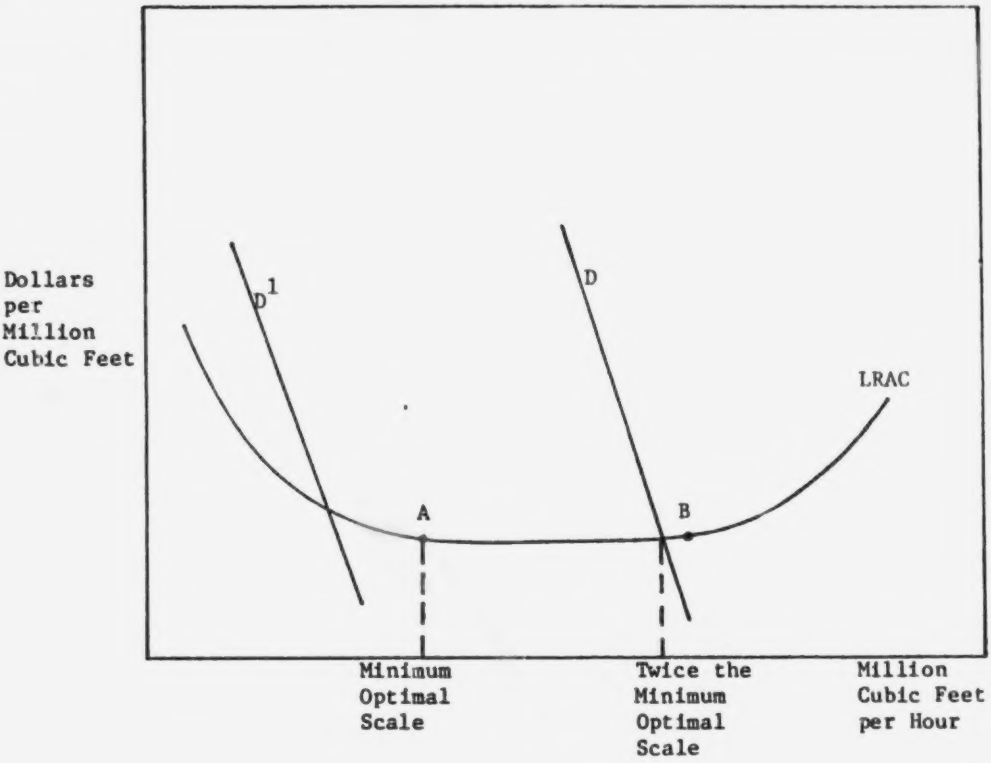
Plant-Specific Economies. - The empirical investigation of economies of scale at the plant or community level is severely hampered by the existence of common and joint costs. Gas distribution companies are typically multiplant or multicommunity operations. Certain items of plant, equipment, and structures, operating and maintenance expenses, and administrative and general expenses are incurred in order to serve several communities simultaneously. These costs conceivably could be allocated among the communities to achieve a rough rule-of-thumb approximation of the actual costs for which each community is responsible. However, such rough approximations are not adequate to determine objectively the extent to which plant-specific economies of scale exist.

Until adequate data becomes available, several important questions remain unanswered. The most important question concerns the minimum optimal scale of operation at the community level. The minimum optimal scale can be defined as the smallest scale at which all economies of scale are realized. It is expressed in terms of rate of output. For natural gas distribution, the ideal measure would be a volume of gas per hour. However, data limitations may greatly inhibit the attainment of this ideal. The minimum optimal scale can be used to determine the number of viable distributors a community can support.

The minimum optimal scale is that size of operations at which the average total cost of output ceases to fall. It can become flat (constant returns to scale) or increase (diseconomies of scale). Figure 1 depicts this phenomena. At point A, the long run average cost (LRAC) reaches its minimum value for the first time; this is the minimum optimal scale. If a plant were built to this scale and operated at capacity, it could serve

FIGURE 1

LONG RUN AVERAGE COST (LRAC) RELATIVE TO MARKET DEMAND AND THE MINIMUM OPTIMAL SCALE


Dollars per Million Cubic Feet
D1
D
LRAC
A
B
Minimum Optimal Scale
Twice the Minimum Optimal Scale
Million Cubic Feet per Hour

consumers at the same cost as a plant the size of B. Plants larger than B or smaller than A incur a higher unit cost. To the left of point A, economies of scale are experienced.

In order to determine the number of distributors a community can support, market demand is introduced. If total market demand is D^1 (see figure 1), economies of scale are present and monopoly would be considered natural. On the other hand, if total market demand is D (see figure 1) constant returns to scale are experienced. In this case, competition as a matter of policy cannot be ruled out. In fact, the diagram is constructed to justify duopoly. The number of distributors a market can support is determined by dividing the total demand per time period by the minimum optimal scale. Competition cannot be ruled out on this basis when the number of distributors exceeds two.

In summary, plant-specific economies for natural gas distribution are difficult to analyze empirically. Data limitations due to the existence of common and joint costs in multiplant operations preclude the exact determination of the cost of rendering service to a community. The estimation of the minimum optimal scale of operations is an important first step to understanding the competitive possibilities at a given point in time. Without knowledge of the minimum optimal scale, even a conclusion of non-increasing returns to scale (constant returns or diseconomies) does not necessarily support desirability of competition. If two firms were to enter, both firms might operate at a scale at which each experiences economies of scale. Here, competition is unstable and will lead to monopoly. By determining the minimum optimal scale for gas distributors, one can determine the number of distributors the market can support.

Multiplant Economies. - By focusing attention on the distribution company, statistical investigation of economies of scale is feasible. In this subsection, the nature of multiplant economies in nature gas distribution is discussed, and tests for its existence are presented. Multiplant economies can emanate from several sources. Potential economies are cost reductions from pooling and coordinating the operation of several plants, capital-raising economies, and procurement economies. In his empirical work, J-M Guldmann developed statistical cost functions for natural gas distribution at the company level. These results do not refute the existence of constant returns to scales at the company (multiplant) level.

Integrating the operation of distribution services for several communities under a single corporate charter can have several benefits. First, by pooling decision-making resources, administrative overhead and general expenses may be reduced because fewer resources will be devoted to this activity. This centralized decision-making could facilitate the planning of future capacity additions and replacements. Potential cost reductions are achievable by strategically expanding the capacity serving more than one community. For instance, transmission mains and storage fields could be developed and shared. Furthermore, if there is substantial diversity in the temporal pattern of demand, the economies of sharing plant, equipment, and structures are enhanced.

The coordinated procurement of gas supplies for several communities could yield some economies. Transaction costs could be reduced. By contracting for all communities simultaneously, resources devoted to negotiating these contracts may be reduced. In addition, by contracting for larger requirements, the risk to the suppliers to the distribution company could be reduced. For instance, production from a field can be dedicated to the company. Other sources of cost savings to the distributor can be an income redistribution at the expense of the supplier. Larger requirements and coordinated purchasing increases the bargaining strength of the distributor. The horizontal integration of natural gas distributors permits them to capture the benefits of the temporal diversity of demand. This can improve their annual load factor if the actual maximum daily demand for a year is smaller than the sum of each community's maximum daily demand. In this case, the distribution company can offer a transmisssion company a higher rate of utilization of its pipeline than could each community separately. This could lead to concessions in the demand charges and other capacity-related prices. This shifts the benefits of diversity from the transmission company forward to the distributor. It is only an income redistribution, however, and as such does not reduce resources devoted to either activity.

Finally, multiplant operations can confer risk-pooling economies on the distribution company. The increased size of the distributor's market and the corresponding benefits of the temporal diversity in demand could reduce the risk to which investors are exposed by purchasing the distributor's securities. Lower risks lead to reductions in the cost of capital.

Each of these potential cost savings could emanate from horizontally integrating distribution service for several communities. Data that would allow the investigation of each of these potential multiplant economies are not available readily, if at all. However, the results of Guldmann's analysis allow inferences to be drawn about overall economies rather than these specific types of multiplant economies.

Professor Guldmann gathered data on 119 U.S. gas distribution utilities. All of his data were for the year 1979 and drawn from the 1979 Annual Reports of the utilities to their state regulatory commissions and the 1979 Uniform Statistical Reports prepared by the utilities for the American Gas Association. The data used in the analysis can be grouped into three categories.

(a) Plant in service data, characterizing the historical cost values of different plant components at the end of 1979.

(b) Operation and maintenance (O&M) costs data, characterizing the O&M cost incurred during 1979.

(c) Market sales and numbers of customers at the aggregate and sectoral levels during 1979.

In table 4, the elasticities for each of his regressions are presented. The explanatory variables are displayed down the left side of the table, while the dependent variables are across the top. The table contains the results of twenty separate regressions. These can be separated into two categories. Eleven of these regressions had aggregated variables as the independent variable. Total sales (TMCF) and total customer size (TCUZ) were used in five regressions, while total sales (TMCF) was used by itself in two regressions. The total number of customers (TCUS) was the independent variable for regressions against general plant (TGEN), customer accounts expenses (CAO), and sales expense (SAO). The remaining ten regressions separated total sales, total customer size, and number of customers into the residential and nonresidential sectors. Similar regressions were run using the sectorial variables. These latter regressions are discussed in the next section on product-specific economies.

The first row of table 4 presents the elasticity of the various cost categories with respect to total sales. The distribution plant and distribution operating and maintenance expenses exhibit constant returns to scale as total sales expand. General plant and administrative and general expenses exhibit constant to mildly increasing returns to scale, while customer service expenses related to total output exhibit constant returns to scale. The significance of the mildly increase returns to scale is questionable. The general plant accounts for only 4.37% of total plant on average. The expense accounts account for 33.34% of total expenses excluding the cost of purchased gas. The cost of purchased gas is a substantial percentage of the variable cost. Thus, the mildly increasing economies could have little overall impact. From the view of statistical hypothesis testing, it is safe to conclude that one cannot refute the existence of constant returns to scale in natural gas distribution.

The elasticities of the various cost categories with respect to the total customer size variables (TCUZ) suggest there exist substantial cost advantages from serving larger as opposed to smaller customers. In fact, a 1% increase in average customer size lowers total cost by 1% or less. These results, while not pertinent to economies of scale, are relevant to the character of a competitive market. Customers with high average sales would be desired customers, while small customers would be shunned. These circumstances could raise issues of cream-skimming in a competitive environment.

In summary; this analysis of the empirical work by Guldmann does not support the hypothesis of economies of scale in natural gas distribution at the company (multiplant) level. Multiplant economies are defined as the

TABLE 4

THE ELASTICITY OF VARIOUS INVESTMENT AND EXPENSE ACCOUNTS WITH RESPECT TO SELECTED EXPLANATORY VARIABLES

Column	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Explanatory Variable	INVESTMENT AND EXPENSE ACCOUNTS								
	TDIST	TDOXP	TDMXP	TGEN	CAO	CSO	SAO	AGO	AGM
TMCF	1.0042	1.0029	1.0849	.9273	----	1.1002	----	.9576	.9527
TCUZ	-.9387	-.9207	-1.0635	----	----	----	----	-.7916	-.7901
RMCF	.8777	.9192	1.0788	.5021	----	.7291	----	.8202	.9453
CIMCF	.1167	.0751	----	.4210	----	.3843	----	.1313	----
RCUZ	-.9897	-.8782	-.8878	----	----	----	----	.6922	-.6297
CICUZ	----	----	----	----	----	----	----	.6403	----
TCUS	----	----	----	1.031	1.0183	----	.9797	----	----
RCUS	----	----	----	1.049	1.0123	----	.9731	----	----
CICUS	----	----	----	----	----	----	----	----	----

Source: Guldmann, J-M, R. Tybout, and W. Pollard, Marginal Cost Pricing for Natural Gas Distribution Utilities, The National Regulatory Research Institute, 1981, Chapter 4.

reductions in the average cost of delivering a volume of gas attributable to increased sales. In this case, competition as a policy cannot be ruled out using the economies-of-scale rationale for a natural monopoly.

Product-Specific Economies. - Product-specific economies are linked to individual product volume rather than overall output. As previously mentioned, a product for a natural gas distributor is defined as the sale of gas to a specific customer class. Two products are defined: residential and nonresidential. Nonresidential customers consist of a distributor's commercial and industrial customers. Thus, product-specific economies refer to reductions in the average cost of delivering a volume of gas to a residential customer or to a commercial customer as the capacity to serve that class expands.

To the extent that this characterization is valid, the problem of common cost is relevant. Common costs refer to investments and expenses incurred that serve both classes of customers. What differentiates common cost from joint cost[1] is the fact that common cost can vary in the proportion serving each class. An increase in residential sales displaces capacity that could serve nonresidential. When common costs are present, each customer class has its own separate identifiable marginal cost curve.

If characterizing sales to residential and nonresidential customers as two products is valid, inferences can be drawn about product-specific economies. The statistical work by Professor Guldmann is again used as a basis for drawing these inferences. Returning to table 4, the relevant rows are those for residential sales (RMCF) and nonresidential sales (CIMCF). Each entry in the table is the elasticity for the corresponding cost category with respect to class sales. Each elasticity taken separately suggests economies of scale. However, sales to each sector utilize common plant, equipment, and structures. In order to assess the impact of an increased volume of gas, one must add the elasticities for each sector. Thus, a one percent (1%) increase in sales for each sector adds approximately one percent (e.g., .8777 + .1167) to total cost for distribution plant and operating and maintenance expenses. General plant and administrative and general operating expense again show evidence of the same mildly increasing economies of scale. From the standpoint of balanced growth, the conclusion pertaining to economies of scale is left intact--constant returns to scale cannot be clearly refuted.

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[1] Joint costs refer to the costs of investments that yield capacity in fixed proportions. So much for product A necessarily entails the requisition of some amount for B. Capacity to serve the peak is available in the off-peak, a joint cost.

Conclusion: Economies of Scale. - The natural monopoly justification for the monopoly provision of natural gas distribution depends on the existence of economies of scale in distribution. This reduction in the average cost of delivering a volume of gas can be plant specific, multiplant (systemwide) specific, or product specific. Empirical work to date does not lend convincing support for this natural monopoly justification when considering multiplant (company level) and product-specific economies. In fact, the existence of constant returns to scale for both types of economies cannot be refuted out of hand.

Constant returns to scale are characteristic of long-run equilibrium in a perfectly competitive market. In practice, constant returns suggest further study might be necessary. One of the most important pieces of information that needs to be determined is the minimum optimal scale for a distribution company. This scale would allow one to determine how many distributors could be supported by a given volume of sales. If two or more firms can be supported, competition as a policy cannot be entirely ruled out.

Rights of Way: A Case of A Scarce Community Resource

Monopoly in natural gas distribution might be desirable if rights of way are a scarce community resource with substantial external costs (borne by society but not the gas company) associated with their use. External costs may occur as a result of nonexistent or ill-defined property rights. Unregulated markets can potentially create external costs because producers can obtain the use of a resource without having to pay the full social cost for its use. Air and water are good examples of such a resource. External cost are costs not borne by the producer, but by groups in society whether they are users or not. Air or water pollution is an example.

In the case of rights of way, the convenience, safety, peace, and health of the community are affected by work on mains along streets and throughfares where most rights of way are located. The franchise, as a policy tool for limiting entry, minimizes this disruption.

Whether the size of the external costs associated with rights of way for gas distribution constitutes an adequate justification for monopoly is an open question. Intuitively, one can imagine the disruptive activities of several competitive utilities performing maintenance on their mains. Unfettered entry or use of rights of way is definitely not in the public interest, but it may be that the market is misperceived. A policy option for state or local government might be to auction the use of rights of way rather than issue franchises. In this way, the price of the rights of way would control entry. Potential entrants would be forced to evaluate the desirability of entry by assessing the potential profits net of the price for using rights of way. Issuance of franchises does not necessarily encourage such cost-benefit comparisons.

In summary, limited entry can be viewed as a method of rationing the scarce community resource of rights of way. Even though limited use may be desirable, creation of monopoly as a matter of policy may not necessarily be in the public interest. The use of the franchise is a direct form of rationing. Price can ration also. Possibilities exist for a competitive bidding process for rights of ways. This method could potentially lead to net benefits for a community, because potential entrants are acting in their own self-interest.

Price Discrimination

Price discrimination frequently is used as a policy tool to achieve social objectives in the regulation of natural gas distribution. Judiciously applied, price discrimination can increase the use of a service throughout a regulatory jurisdiction, promote economies of utilization for the existing system, promote economies of scale, and reduce rates to all customer classes.[1] When applied by an unregulated monopoly, price discrimination can sap the economic vitality of a market and cause a lot of social harm. The following discussion examines the issues of price discrimination in natural gas distribution and its implications for a competitive policy.

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[1] See Phillips, Charles F. Jr., The Economics of Regulation, Richard D. Irwin Co., pp. 303-310.

Price discrimination is defined as charging different purchasers prices that differ by varying proportions from the respective marginal costs of serving them.[1] Pricing below the marginal cost of serving a customer constitutes predatory pricing. With natural gas distribution, the nature of the end-use to which gas is put is a basis for price discrimination. In this case, charging customer classes prices that are not justified by corresponding variations in the marginal costs of service constitutes its practice.

Natural gas distribution has certain features that may lean the industry toward the practice of price discrimination. In particular, the physical connection between the producer and the consumer is a potent instrument for facilitating its practice. The necessary conditions for it are the following:

1. Monopoly or near-monopoly in rendering the service.
2. Markets capable of being separated by the elasticity of demand for each submarket.
3. Prevention of resale from the low-priced market to the high-price market, that is, preventing arbitrage.

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[1] Kahn, Alfred, The Economics of Regulation, Vol. 1, p. 123.

Each of these conditions and the related circumstances for natural gas distribution are discussed below, and the implications of these for competitive policy are also addressed.

Markets for natural gas distribution can be separated by elasticity of demand by examining the uses for gas. Elasticity of demand primarily depends on the number of substitutes available, percentage of income spent on the good, the necessity of the good, and the postponability of the purchase. Since gas cannot be stored by consumers, purchase cannot necessarily be postponed or expedited. This tends to reduce the responsiveness of the quantity demand to changes in the price of gas. The total purchase price of gas, or any energy source, requires the consumer to purchase or lease an end-use appliance. The prices for end-use appliances are subject to competitive market forces. A rational consumer evaluates the use of one energy source relative to another by weighing the present value of the expense of using one source, including the annual cost of the end-use appliance, relative to another. However, once the investment in the end-use appliance is made, the consumer has limited substitution possibilities. (The substitution of one energy source for another would be cost effective only if the present value of the increment in the cost of using gas exceeds the cost of a new end-use appliance for an alternative energy source less the salvage value of the existing gas appliance.) A substitution presumably requires a substantial change in the conditions that initially induced the consumer to choose gas. This aspect of the demand side of the gas market results in a certain latitude with which gas prices can be varied without having most customers switch to another fuel.

Both the foregoing considerations indicate that natural gas users may have limited flexibility in responding to price changes. Adjustments can be made, but with a time lag. The implication of this for a competitive policy in natural gas distribution is as follows.

The role of elasticity of demand in price discrimination is fairly straightforward. Price can deviate more from marginal costs in submarkets where customers lack a sufficient degree of flexibility (less elastic demand). Prices are set closer to marginal costs where customers have sufficient flexibility. Such a pricing scheme enables the distributor to earn profits above and beyond those available if he were to charge a price that deviated equally for all customers from the marginal cost of serving them.

For price discrimination to be effective, competition must be minimal and the submarkets prevented from selling to one another. Arbitrage of the high and low priced markets is prevented under current regulatory practices by the existence of the physical connection and laws preventing unauthorized hookups. Such legal provisions can be justified on safety and health grounds. These reasons should prevail irrespective of competitive policy.

The ability of competitive gas distributors to check price discrimination in the provision of service through abritrage is not readily obvious. In particular, the number of competitive distributors a market can support is an important consideration. As stated previously, oligopoly or collusive monopoly could be the probable outcome of a competitive market for distribution services. This would probably only eliminate the most virulent and unjust discriminatory practices.

Entry of distributors could make matters worse. Cream-skimming and entry to selected markets could accentuate certain discriminatory practices. Existing distributors could alter the relative prices for gas among markets. Excess profits could be earned in markets where competition is less intense to support the company in the more competitive markets. This cross-subsidization of markets and the corresponding potential for predatory pricing would be a clear danger. As a result, any potential for competition is dampened by the possibilities for price discrimination.

Vertical and Horizontal Integration

The shortages of natural gas and the accompanying curtailments during the 1970's prompted natural gas distributors to form joint ventures to explore and develop natural gas fields. This behavior can have potentially far reaching effects on the structure of the natural gas industry and create potential monopoly problems for state and federal regulators. In particular, by gaining control over the source of supply at the wellhead, the distributor's potential for earning monopoly profits is enhanced.

Backward integration by a natural gas distributor destroys the arms-length bargaining relationship between a pipeline and a distributor. When the distributor has no financial interest in the natural gas he purchases from a pipeline, he has a clear incentive to bargain strenuously for his gas supplies. As a result, he has little to gain by restricting gas services to customers. In fact, one can expect distributors to file complaints and intervene in rate cases affecting the price of gas from interstate and intrastate piplelines. This is, in fact, the case. This arm-length relationship can be a fairly dependable tool with which public utility commissions can be assured that gas supplies are reasonably priced, providing that adequate price information is available to all. However, once a distributor has a financial interest in selling gas, as well as buying it, state commissions can no longer depend on the arms-length relationship. It is in the distributor's interest to restrict the supply of natural gas and purchase it at an unreasonably high price. In doing this, he can extract monopoly profits from his distribution customers and earn them on his investment in production. Thus, backward integration enables a distributor to realize monopoly profits from his regulated markets.

Joint ventures among distributors exacerbate the problems associated with backward integration. Joint ownership of gas wells diminishes the possibility that any one distributor would protest the price of that gas. Furthermore, it distorts the standard of comparability for prices of gas. If distributors in a given pricing area are obtaining incremental supplies of gas from a well they jointly own, regulatory commissions would find it more difficult to develop standards by which to evaluate the reasonableness of the price of gas.

Interproduct Competition

Competition among energy suppliers has been quite effective in eroding the market share of natural gas. Shortages and subsequent curtailments of gas, particularly to interruptible customers, led to declining sales and revenues in the latter part of the 1970's. As a result, gas distributors have come to embrace the goal of revenue stability. This goal manifests itself in several ways. One objective of distributors is to gain credibility with industrial customers; distributors want to prove themselves a reliable source of energy. As discussed above, backward integration into production is one method of assuring a reliable source of gas. Interproduct competition has also led to attempts to engage in certain anticompetitive pricing practices. These pricing schemes, while subject to regulatory control, represent attempts to foreclose their markets to competitive inroads.

Two instances are presented below. One is specific, while the other simply describes a set of circumstances. The first involves an attempt by Columbia Gas of Ohio (a distribution company) to foreclose the combination of electric heat pump and gas furnace in residential homes. The other is about a distributor and an industrial customer on the west coast.

Columbia Gas of Ohio tried to impose a $12 surcharge on gas space-heating customers who also installed electric heat pumps. Columbia's rationale focused on the low load factor that this type of customer would exhibit. Gas heat in such homes is used to supplement heating needs only during the coldest periods. It would be used in lieu of high cost electric resistance heating. Columbia argued that such a use of gas imposed a cost on all the other customers in its system.[1]

The problem that gave rise to the situation was the artificially low price of gas as regulated at the wellhead. A competitive pricing problem existed that required adjustments in the rates for gas and/or electric space heating. The outcome was that Columbia dropped its request for the surcharge, which the Public Utilities Commission of Ohio might well have denied. Public outcry prevented this request from getting to a rate case. If put into effect, however, the surcharge would have inhibited a competitive use of electricity for gas.

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[1] See Columbia Gas Distribution Companies, New Load Evaluation Techniques, Mimeo.

In another situation, a west coast industrial firm wished to take advantage of the glut of oil experienced on the west coast. Previously, it had obtained all of its energy requirements from the local gas distributor. The industrial customer installed fuel switching capabilities to use both gas and oil. This cost-effective strategy enabled the customer to hedge his commitment to either gas or oil because of the uncertainty surrounding the supply or price of both.

The gas distributor's reaction was predictable. It feared the loss of revenues to a competitive source of energy. Upon being informed, the distributor's spokeman informed the industrial customer that the gas company would be out to remove the meter at the service drop. This threat of withdrawal of service had its impact. The industrial customer's investment in end-use equipment would be rendered useless. The situation required negotiation.

The distributor won contract concessions with the industrial customer. Something similar to a take-or-pay charge was negotiated. The industrial customer had to pay for a certain percentage of his peak gas demand whether he used it or not. The distributor, by virtue of his monopoly position, was able to enhance his revenue stability in the face of competitive inroads. State regulation of gas distribution has the potential to control this monopoly behavior when brought to its attention.

Conclusions on Monopoly in Natural Gas Distribution

State public utility commissions and local authorities enforce monopoly in the provision of natural gas distribution service with the certificate of convenience and necessity and the franchises. Monopoly and limited entry are believed to be in the public interest for three somewhat interrelated reasons. Duplicate facilities are alleged to be wasteful either because economies of scale exist and monopoly is therefore natural or because competition is destructive. The scant empirical evidence that is available does not support the hypothesis of economies of scale. In fact, constant returns to scale seems to prevail. This implies that competition is feasible. Offsetting this conclusion, however, is circumstantial evidence supporting the hypothesis of destructive competition. Indivisibilities of certain investment costs create incentives to install unused or excess capacity. This fact coupled with the high investment cost in a specialized and relatively immobile resource creates conditions favorable to destructive competition. In these circumstances, monopoly might best serve the public interest. A conclusive demonstration of the potential for competition would entail the estimation of the minimum optimal scale of a distribution system. This scale of operation would enable one to determine the number of firms a given market could sustain. Beyond these reasons for monopoly and even if competition is feasible, state and local policymakers recognize that rights of way are scarce community resources. Unregulated use of the rights of way could be disruptive to the safety, health, and peace of a community. Thus, the potential for destructive competition and the limited availability of rights of way tend to support monopoly in natural gas distribution as being in the public interest.

The physical connection between the distributor's supply point and the consumers' premises constitutes a majority of the distributor's plant and equipment. This connection and cost are inextricably intertwined with the above reasons supporting monopoly and have important implications. The physical connection and laws preventing unauthorized hookups create conditions favorable for price discrimination. Intraproduct and interproduct competition may not constitute sufficient market forces to check price discrimination. In fact, intraproduct competition may lead to cross-subsidization between markets to foreclose competition through limit or predatory pricing.

Vertical integration backward into gas production by distributors has escalated in the past few years. An interest in revenue stability and assured supplies of gas has led distributors to develop their own sources of supply through direct investment or joint ventures with other distributors. This tendency threatens the arms-length bargaining relationship that has often previously facilitated state regulation of distributors. At risk are the standards of comparability that public utility commissions can rely on to assure that gas is purchased at reasonable prices.

Finally, interproduct competition raises a potpourri of issues. At the forefront are issues of competitive rate structures for natural gas and threats of withdrawals of service. State public utility commissions frequently take an active role in addressing and resolving these issues.

The alternatives of a regulated, quasi-regulated, or competitive gas distribution industry can be considered in view of these factors. Interproduct and intraproduct competition in natural gas distribution does not necessarily offer a better alternative to regulation for resolving these issues.

Impact of Federal Regulation on State Regulation

The effect of federal regulation on state regulation of natural gas distribution has been pervasive. Federal regulation determines wellhead prices. Because federal regulation controls wellhead prices, states have been essentially helpless to control a major portion of costs and, hence, prices to the end users. Federal regulation also affects pipeline transmission rates because the Federal Energy Regulatory Commission (FERC) regulates the pipeline transmission rates of interstate gas and intrastate gas in interstate pipelines. In addition, the Natural Gas Policy Act of 1978 places additional restrictions on state ratemaking authority over intrastate utilities. These major impacts of federal regulation upon state public utilities are discussed below.

The Effect of Federal Regulation of Wellhead Prices

Prior to the gas shortages of the mid-1970's, the Federal Energy Regulatory Commission (FERC) regulated the wellhead price of gas consumed in the interstate pipeline system. (Beginning in 1976, the FERC allowed the interstate transport, at a regulated rate, of gas with an unregulated wellhead price to large curtailed customers under certain conditions.) The wellhead price of gas not in the interstate pipeline system, that is, intrastate pipeline gas, was either unregulated or regulated by state regulatory commissions.

The Emergency Natural Gas Act of 1977 (ENGA) and the Natural Gas Policy Act of 1978 (NGPA), however, changed this scheme. While ENGA created conditions for federal control of intrastate gas prices, NGPA actually brought wellhead pricing of all gas produced within the United

States under federal jurisdiction. Under NGPA, FERC lost its authority to set wellhead prices, but was charged with identifying and enforcing the legal prices to be charged for various categories of gas spelled out in the NGPA. The FERC delegates to the states the initial identification of the price categories for gas. (A discussion of the several categories of gas is presented in an earlier chapter of this report.) The delegation of identification of price categories for new wells usually went to state agencies more familiar with drilling and production activities than state utility regulatory commissions. Some believe that these state authorities are often understaffed and without sufficient personnel to determine the appropriate category for each well and each transaction.

As noted above, the primary effect of federal regulation of wellhead prices is that states are essentially helpless to control a major portion of costs, the costs of gas production, and hence are helpless to control a major portion of prices to the end users. The NGPA has been blamed for distortions in the gas market. For example, by deregulating high-cost gas, while keeping most other gas prices depressed, the NGPA induces production of high cost gas at a price that is much higher than the market clearing price of gas. This is possible because the deregulated gas is rolled-in with the price of regulated gas. Thus, the NGPA has created a powerful incentive for the most expensive gas to be produced before the cheapest gas. This has been labeled a misallocation of resources. State utility regulatory commissions are left with little choice but to pass the cost of gas priced according to federal wellhead pricing on to the end users.

Another effect of federal determination of wellhead pricing is that most of the intrastate gas production was essentially deregulated at the time of the passage of the NGPA. Thus, the NGPA puts intrastate pipelines at a disadvantage because they have little cheap gas to roll in with expensive new sources of gas. This disadvantage could cause significant economic disruptions to industry and gas distribution companies dependent upon intrastate gas. Furthermore, if the NGPA runs its course in 1985, the greater portion of intrastate gas will be decontrolled, compounding this problem. State utility regulatory commissions are, once again, essentially helpless to solve these potential problems.

The Effect of Federal Regulation of Pipeline Rates

The Federal Energy Regulatory Commission, prior to the enactment of the National Energy Act in 1978, regulated the pipeline transmission rates of interstate pipelines. State utility regulatory commission regulated the pipeline transmission rates of intrastate pipelines.

Congress made provision for the phased deregulation of certain categories of new natural gas in Title I of the NGPA. In order to soften the impact of deregulation and in order to prepare the marketplace for an orderly transition, Congress also enacted Title II of the NGPA that provides for the imposition of surcharges to be paid by certain industrial customers. Title II of the NGPA provides that initially all large industrial boiler fuel consumers of gas served off the interstate pipeline system either directly or indirectly, except agricultural users, would be assigned the incremental cost of new gas. The NGPA provides that each of these industrial facilities would continue to be assessed the higher cost of new gas until their gas cost equaled the cost of alternative fuel, number 2 oil. However, if the FERC found that a lower price was necessary to prevent a migration of industry switching to another fuel, the FERC could set the cost of the alternate fuel to the equivalent cost of number 6 oil.

Phase one of the incremental pricing became effective on January 1, 1980, and the FERC designated high sulfur number 6 oil as the alternate fuel.

The NGPA also provides for extension of incremental pricing to all industrial customers regardless of the end use application of the gas. The implementation date of this phase will occur only after the Congress has had an opportunity to review the proposed plan. Either house of the Congress may veto Phase II. Thus far, the only plan submitted to the Congress by the FERC has been vetoed by the House of Representatives.

The primary effect on state utility regulatory commissions concerning FERC setting the rates charged by interstate gas pipeline company is that state utility regulatory commissions must flow these charges through to the ultimate end users. While the state utility regulatory commission has some discretion on spreading the interstate pipeline charges to various customer classes, there are restrictions placed upon state ratemaking authority by the NGPA. These are noted below.

The state utility regulatory commission is free to set the rates charged by intrastate gas pipeline companies for transmissions. However, as noted above the state utility regulatory authority is not free to set the wellhead price of intrastate gas, the major component of the cost of gas. State utility regulatory commissions still have full discretion to regulate the price of gas from intrastate supplies and to spread costs to customers as they see fit.

The Effect of Federal Regulation on Distribution Rates

The principal restriction imposed by the NGPA on state ratemaking authority over intrastate gas distribution companies concerns incremental pricing. Section 205 of the NGPA requires that any surcharge under Title II of the NGPA paid by a local gas distribution company, due to gas being indirectly delivered by an interstate pipeline to an incrementally priced industrial customer of the local distribution company, be directly passed through to the incrementally priced industrial customer. Section 205 also prohibits the state utility regulatory commissions from making any modifications to the rates charged to incrementally priced industrial customers that has the effect of offsetting the surcharge. Also, section 205 of the NGPA, provides for federal preemption of any state or local law that would preclude the passthrough of the surcharge to the industrial customer.

Title II of the NGPA has placed an additional administrative burden upon state utility regulatory commissions. The state commissions are required by the NGPA to require the flow through of any surcharge to utilities facing an incrementally priced supply and are prohibited from allowing any rates or charges to take effect that would offset the surcharge. Because of the gas supply "bubble" on the market in 1981, most gas distributors are attempting to market their gas supply. In particular, gas distribution companies are likely to view the industrial market as an appealing market offering new opportunities especially as oil prices escalate. Because of these marketing pressures, a gas distribution company is likely to be tempted to design rates for industrial customers so as to offset the effect of the NGPA Title II surcharge. To prevent gas distribution companies from enacting tariffs violating NGPA Title II, state utility regulatory commissions need to be vigilant and devote staff resources to this issue.

In effect, Title II of the NGPA preempts a portion of state ratemaking authority by prohibiting the use of any costing methodologies that would have the effect of offsetting the flow through of the NGPA Title II surcharge. For instance, if a state utility regulatory commission wanted to price according to a marginal cost methodology, it would need to guarantee that the results of the methodology did not offset the effect of the NGPA Title II on incrementally priced industrial customers. State utility regulatory commissions thus are not completely free to exercise their ratemaking authority when setting rates for gas from interstate pipelines. State utility regulatory commissions, however, are fully free to exercise their ratemaking authority when designing rates concerning gas from intrastate pipelines.

The Effects of Other Federal Regulations on State Regulation

Federal regulations regarding taxes and the environment have an effect on state regulation. Federally prescribed accelerated depreciation, investment tax credits and tax policies bear on state utility regulatory commission regulation. Also, past federal environmental regulation has had secondary effects on state utility commission regulation of natural gas distribution. Federal regulation has also addressed rate reform by state regulatory commissions because of the studies required by the Public Utility Regulatory Policies Act of 1978 (PURPA). Also, federal regulation of the end use of gas has restricted certain classes of natural gas consumption, while the Natural Gas Policy Act of 1978 (NGPA) has provided for curtailment of certain end uses of gas in the case of a severe gas shortage.

The Effects of Federally Prescribed Depreciation, Investment, and Tax Policies. - Tax normalization is the regulatory counterpart of the financial accounting concept of comprehensive allocation. Tax normalization involves charging to tax expense each year the tax liability the company would have incurred if, instead of using an accelerated method of depreciation for tax purposes, it had used the straight-line method. During the early life of the asset, the excess of the hypothetical straight-line tax amount over the actual tax paid is accumulated in a reserve for deferred taxes. Later, when the actual tax bill rises over the straight-line figure, the reserve is written off. The net result of using normalized taxes and straight-line depreciation for ratemaking is to give the utility the equivalent of an interest-free loan.

Prior to the Economic Recovery Tax Act of 1981, the Tax Reform Act of 1969 placed certain limitations on the use of accelerated depreciation methods for post-1969 public utility property (public utility property that was public utility property in the hands of any person after December 31, 1969). A utility could only use an accelerated method of depreciation if the utility engaged in tax normalization or if the utility elected to engage in flow-through accounting and if flow-through was used for similar property previously. The useful life of public utility property with accelerated depreciation that is normalized could be set by the Asset Depreciation Range System (ADR). Under the Revenue Act of 1971, a 10%

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investment tax credit was available for certain qualifying public utility property if neither rate base nor the cost of service is reduced or under certain other limited circumstances.

The Economic Recovery Tax Act of 1981 has a mandatory system for assets placed in service after December 31, 1980. This Act shortens the service life of assets for depreciation purposes. The Act provides that public utility property with a current ADR life of 18 years or less becomes 5-year property, public utility property with a current ADR life of 18 to 25 years becomes 10-year property, and that public utility property with an ADR class life of over 25 years becomes 15-year property for the purposes of depreciation. The Act also provides for accelerated depreciation methods on the property. It requires that the accelerated depreciation be normalized and provides a transition until December 31, 1982 for companies presently using a "flow-through" method to normalize.

The Economic Recovery Tax Act of 1981 also provides for a 10% investment tax credit for all property except 3-year property. The Act also enacts new safe harbor rules concerning personal property leasing that has the effect of expanding personal property leasing.

Federal tax regulation has had the effect of encouraging, if not requiring, state public utility commission to allow normalization of accelerated depreciation and investment tax credits, and to discourage, if not prohibit, flow-through of the benefits of accelerated depreciation to the ratepayers. Some analysts contend that normalized tax treatment of accelerated depreciation and investment credits may create an unintended incentive for utilities to overestimate forecasted demand growth and to build excess capacity. Most state public utility commissions have the responsibility of ratemaking with tax normalization. Most commissions also review the utilities expansion plans.

The new tax act will also have the effect of encouraging personal property leasing of capacity of public utilities. State public utility commissions will probably need to decide whether or not a qualifying corporate lessor becomes a "public utility" and thus falls under the state utility commission's jurisdiction.

The Secondary Effects of Past Environmental Regulation. - The Clean Air Act of 1970 subjects all major new or modified stationary sources of air pollution, such as a power plant, to new source performance standards. New source performance standards effectively limit emissions of sulfur dioxide, nitrogen oxides, particulates, and other pollutants. In addition to meeting the new source performance standards, a new or modified power plant must have the lowest achievable emission rate for a particular pollutant if the new or modified plant is located in a nonattainment area for that pollutant. If the new or modified plant is located in a "clean area", and the net change in emissions of a particular pollutant is above certain de minimis levels, then the new or modified plant must be equipped with the best available control technology for that particular pollutant. In order to meet these regulations and other Environmental Protection Agency regulations concerning water and solid waste, electric utilities spent nearly $7.2 billion in 1980. Because of the expense of pollution control devices, such utilities often built gas peaking units to meet demand growth rather than high-sulfur oil, or coal plants, which often require massive investments in pollution control devices to meet the requirements of the Clean Air Act of 1970. However, the Fuel Use Act of 1978 prohibited the use of natural gas as a primary fuel for new electric power plants, and limited the use of natural gas in existing power plants to the average yearly usage between 1974 through 1976. These limitations have contributed in some areas to excess capacity and higher costs. State utility commissions set rates for gas utilities affected by the Fuel Use Act of 1978.

Possible Future Effects of Certain Other Existing Federal Laws. - The Fuel Use Act of 1978 has the present and future effect of prohibiting new electric power plants using natural gas as a primary energy source, unless there is an exemption. 1/ The reasons for granting exemptions include lack of alternative fuel supply, site limitations, the plant being in the public interest, the plant being granted a permanent exemption as a peakload plant, the plant being granted a permanent exemption as an intermediate load power plant, the plant burning certain fuel mixtures containing natural gas, the plant being necessary to meet scheduled equipment outages, the plant cogenerates, the power plant being maintained and operated only for emergency purposes, the power plant being necessary to maintain reliability, or the installation being based upon product or process requirements.

Section 301, the Off-Gas Provision, of the Fuel Use Act of 1978 was repealed in the Omnibus Budget Act of 1981. A new section 301 requires utilities using natural gas as a primary energy source in an existing power

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1/ The Fuel Use Act has recently been eliminated.

plant to submit to the U.S. Department of Energy a conservation plan which will reduce by 10%, in five years, the utility's electric output attributable to natural gas. Utilities experiencing load growth need only to plan for a reduction in the trend line of their gas use. While the utilities are required to implement their plans, there are no penalties if the 10% reduction in gas usage is not achieved.

Title III, Section 306 of PURPA required the Department of Energy to undertake a gas utility rate design study addressing several approaches to rate design including marginal cost pricing, demand-commodity rate design, declining block rates, interruptible service, seasonal rate differentials and end-user rate studies. The study was also required to address three other issues: incremental pricing, wellhead natural gas pricing policies, and end-user consumption taxes. Each of the general approaches to rate design and the three issues were to be evaluated in terms of the three objectives of PURPA--equity, conservation, and utility efficiency. The report was presented to Congress in May 1980.

Upon completion of the study, the Secretary of the Department of Energy is required to develop proposals and legislative recommendations to improve gas utility rate design and encourage conservation of natural gas. The proposals and legislative recommendation are to be transmitted to the Congress by November 1980. 2/ Congress is not required to take action upon the recommendations of the Secretary of the Department of Energy, and has not taken action, thus far. If Congress takes no action, then the State utility commissions are free to continue to set their own gas pricing

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2/ No report of this kind has been transmitted to the Congress.

policies subject to the constraints imposed by the NGPA. If, however, Congress elects to endorse some of the recommendations, rate design to end-use consumers could be mandated by federal legislation.

Finally, under Sections 301 through 304 of the Natural Gas Policy Act of 1978, the President has the authority to declare a natural gas supply emergency whenever the supply of natural gas for high priority users is endangered in any region of the United States. High priority users include those who use natural gas in a residence; in a commercial establishment at volumes of less than 50 MCF on a peak day; in any school, hospital, or similar institution; or, in any other location that the Secretary of Energy determines is important to life, health, or maintenance of physical authorize interstate pipelines and local distribution companies served by interstate pipelines to make emergency sales. If high priority users are still not satisfied, the President can then reallocate boiler fuel gas.

In addition, all curtailment plans of interstate pipelines must meet the minimum standards of Section 401 and 402 of the Natural Gas Policy Act of 1978. These requirements could reflect state public utility regulation in the future by effectively foreclosing the options of a state public utility commission during a natural gas supply shortage.

APPENDIX

Detailed Scope of State Authority

Most state public utility commissions have the authority to regulate retail rates for natural gas charged by gas companies to final users. As indicated in column one of table A-1, all state utility commissions (with the exception of Nebraska, which does not regulate electric or gas utilities) have authority over retail rates charged to ultimate consumers by investor-owned utilities. However, only one-third of the state commissions may regulate the rates charged to ultimate consumers by publicly-owned gas companies. The least frequently regulated retail rates are on sales to industrial customers by interstate pipeline companies and gas producers that are under commission ratemaking authority. They are regulated in 11 and 7 states, respectively. As shown in the last four columns of the table, sales by private gas companies to the U.S. government and to public authorities are under the ratemaking authority of state commissions in 48 states. However, when the vendor is a publicly-owned utility, only 16 states have authority to regulate rates for sales to a public authority, and only 17 states have authority to regulate the rates for sales to the U.S. government.

The authority of state commissions to regulate wholesale rates for natural gas is more limited as illustrated in table A-2. The term, TABLE A-1*

STATE AGENCY AUTHORITY TO REGULATE RETAIL RATES FOR NATURAL GAS SALES BY STATE, 1979

Column Agency	(1) Sales to Ultimate Consumers by Private Companies	(2) Sales to Ultimate Consumers by Public Companies	(3) Sales to Industrial Customers by Interstate Pipeline Company	(4) Sales to Industrial Customers by Gas Producers	(5) Sales to Public Authorities by Private Companies	(6) Sales to Public Authorities by Public Companies	(7) Sales to the U.S. Government by Private Companies	(8) Sales to the U.S. Government by Public Companies
Alabama	Y	N	N	N	Y	N	Y	N
Alaska	Y	Y	Y	Y	Y	Y	Y	Y
Arizona	Y	N	N	Y	Y	N	Y	N
Arkansas	Y	N	N	Y	N	N	Y	N
California	Y	N	N	N	Y	N	Y	N
Colorado	Y	Y 1/	N	N	Y	Y 1/	Y	Y 1/
Connecticut	Y	N	N	N	Y	N	Y	N
Delaware	Y	N	N	N	Y	N	Y	N
D.C.	Y	N	N	N	Y	N	Y	N
Florida	Y	N	N	N	Y	N	Y	N
Georgia	Y	N	N	N	Y	N	Y	N
Hawaii	Y	N	N	N	Y	N	Y	N
Idaho	Y	N	N	N	Y	N	Y	N
Illinois	Y	N	Y	N	Y	N	Y	N
Indiana	Y	Y	N	N	Y	Y	Y	Y
Iowa	Y	N	Y	N	Y	N	Y	N
Kansas	Y	2/	N	N	Y	2/	Y	2/
Kentucky	Y	N	N	N	Y	N	Y	N
Louisiana	Y 3/	N	N	N	Y	N	Y	N
Maine	Y	Y 4/	N	N	Y	Y 4/	Y	Y 4/
Maryland	Y	Y	N	N	Y	N	Y	Y
Massachusetts	Y	5/	N	N	Y	5/	Y	5/
Michigan	Y	N	Y	N	Y 6/	N	Y	N
Minnesota	Y	N	N	N	Y	N	N	N
Mississippi	Y	Y	N	N	Y	Y	Y	Y
Missouri	Y	N	N	N	Y	N	Y	N
Montana	Y	Y	Y	Y	Y	Y	Y	Y
Nebraska 7/	N	N	N	N	N	N	N	N
Nevada	Y	8/	Y	N	Y	8/	Y	8/
New Hampshire	Y	N	N	N	Y	N	Y	N
New Jersey	Y	N	N	N	Y	N	Y	N
New Mexico	Y	9/	Y 10/	N	Y	9/	Y	9/
New York	Y	Y	N	N	Y 11/	Y 11/	Y 11/	Y 11/
North Carolina	Y	N	Y	N	Y	N	Y	N
North Dakota	Y	N	N	N	Y	N	Y	N
Ohio	Y	N	N	N	Y	N	Y	N
Oklahoma	Y	N	N	N	Y	N	Y	N
Oregon	Y	4/	N	N	Y	4/	Y	4/
Pennsylvania	Y	Y 12/	N	N	Y	Y 12/	Y	Y 12/
Rhode Island	Y	Y	N	N	Y	Y	Y	Y
South Carolina	Y	N	N	N	Y	N	Y	N
South Dakota	Y	N	N	N	Y	N	Y	N
Tennessee	Y	N	Y	N	Y	N	Y	N
Texas	Y	Y	N	Y	Y	Y	Y	Y
Utah	Y	N	Y	Y	Y	N	Y	N
Vermont	Y	Y	N	N	Y	Y	Y	Y
Virginia	Y	N	N	N	N	N	N	N
Washington	Y	N	N	Y	Y	N	Y	N
West Virginia	Y	N	N	N	Y	Y	Y	Y
Wisconsin	Y	Y	4/	4/	Y	Y	Y	Y
Wyoming	Y	Y 14/	Y 15/	N	Y	Y 14/	Y	Y 14/

Source: Paul Rodgers, 1979 Annual Report on Utility and Carrier Regulation of the National Association of Regulatory Utility Commissioners (Washington, D.C.: NARUC, 1980) pp. 392-7.

*For tables A-1 through A-19, a "Y" means that a state agency does have the described authority, and an "N" means that the state agency does not have the described authority.

1/ Public utilities regulated when outside of municipal boundary only.
2/ Same as for private utilities and co-ops for facilities outside of 3 miles from the corporate limits of municipalities. Commission has no jurisdiction within the 3 mile limit.
3/ Except no authority over rates charges to industrial customers by any gas company.
4/ None in state.
5/ Only if earnings exceed 8 percent of original cost of plant in service or if discrimination between classes of customers.
6/ Commission jurisdiction excluded from rates covered by special agreements with municipalities.
7/ Telephone is the only regulated utility.
8/ Municipal utilities exempt from state regulation.
9/ Intercommunity natural gas association (owned by 2 or more municipals) should be answered the same as private gas utilities.
10/ Authority not exercised.
11/ Jurisdiction over all rates either by tariff or contract.
12/ Only when service extends beyond the corporate limits of a publicly owned utility company.
13/ The Railroad Commission of Texas has safety jurisdiction over municipally owned gas utilities and appellate rate jurisdiction over these utilities outside the corporate limits of the city.
14/ Public utilities regulated in so far as they are owned and operated outside corporate limits.
15/ To the extent not regulated by FERC.

TABLE A-2

STATE AGENCY AUTHORITY TO REGULATE WHOLESALE RATES FOR NATURAL GAS SALES BY STATE, 1979

Column Agency	(1) Sales to Public Authorities by Private Companies	(2) Sales to Public Authorities by Public Companies	(3) Sales to U.S. Government by Private Companies	(4) Sales to U.S. Government by Public Companies	(5) Sales to Privately-Owned Companies by Private Companies	(6) Sales to Privately-Owned Companies by Public Companies	(7) Sales to Publicly-Owned Companies by Private Companies	(8) Sales to Publicly-Owned Companies by Public Companies
Alabama	Y	N	Y	N	Y	N	Y	N
Alaska	Y	Y	Y	Y	Y	Y	Y	Y
Arizona	Y	N	Y	N	Y	N	Y	N
Arkansas	N	N	N	N	N	N	N	N
California	Y	N	Y	N	Y	N	Y	N
Colorado	Y	Y 2/	Y	Y 2/	Y	Y 2/	Y	Y 2/
Connecticut	N	N	N	N	N	N	N	N
Delaware	N	N	Y	N	Y	N	N	N
D.C.	N	N	N	N	N	N	N	N
Florida	N	N	N	N	N	N	N	N
Georgia	Y	N	Y	N	Y	N	N	N
Hawaii	Y	N	Y	N	Y	N	Y	N
Idaho	N	N	Y	N	Y	N	N	N
Illinois	Y	N	Y	N	Y	N	Y	N
Indiana	N	N	N	N	N	N	N	N
Iowa	N	N	N	N	N	N	N	N
Kansas	Y	3/	Y	3/	Y	3/	Y	3/
Kentucky	N	N	N	N	N	N	Y	N
Louisiana	N	N	N	N	N	N	N	N
Maine	Y	Y 4/	Y	Y 4/	Y	Y 4/	Y	Y 4/
Maryland	N	N	N	N	N	N	N	N
Massachusetts	Y	5/	6/	6/	6/	6/	6/	6/
Michigan	7/	N	7/	N	7/	N	7/	N
Minnesota	N	N	N	N	N	N	N	N
Mississippi	N	N	N	N	N	N	N	N
Missouri	N	N	Y	N	Y	N	N	N
Montana	Y	Y	Y	Y	Y	Y	Y	Y
Nebraska 8/	N	N	N	N	N	N	N	N
Nevada	Y	9/	Y	9/	Y	9/	Y	9/
New Hampshire	Y	N	Y	N	Y	N	Y	N
New Jersey	Y	N	Y	N	Y	N	Y	N
New Mexico	Y 10/	11/	Y 10/	11/	Y 10/	11/	Y 10/	11/
New York	Y	Y	Y	Y	Y	Y	Y	Y
North Carolina	N	N	N	N	N	N	N	N
North Dakota	N	N	N	N	N	N	N	N
Ohio	N	N	Y	N	Y	N	N	N
Oklahoma	Y	N	Y	N	Y	N	Y	N
Oregon	N	4/	N	4/	N	4/	N	4/
Pennsylvania	Y	Y 12/	N	N	N	N	N	N
Rhode Island	Y	Y	Y	Y	Y	Y	Y	Y
South Carolina	Y	N	Y	N	Y	N	Y	N
South Dakota	N	N	N	N	N	N	N	N
Tennessee	Y	N	Y	N	Y	N	Y	N
Texas	Y	Y	Y	Y	Y	Y	Y	Y
Utah	Y	N	Y	N	Y	N	Y	N
Vermont	N	N	N	N	N	N	N	N
Virginia	N	N	N	N	N	N	N	N
Washington	Y	N	Y	N	Y	Y	Y	N
West Virginia	Y	Y	Y	Y	Y	Y	Y	Y
Wisconsin	Y	Y	Y	Y	Y	Y	Y	Y
Wyoming	14/	14/	14/	14/	14/	14/	14/	14/

Source: Paul Rodgers, 1979 Annual Report on Utility and Carrier Regulation of the National Association of Regulatory Utility Commissioners (Washington D.C.:NARUC, 1980) pp. 392-7.

1/ Rates for interstate sales are subject to the jurisdiction of the FERC; intrastate rates are subject to state regulation.
2/ Public utilities regulated when outside of municipal boundary only.
3/ Same as for private utilities and co-ops for facilities outside of 3 miles from the corporate limits of municipalities. Commission has no jurisdiction within the 3 mile limit.
4/ None in state.
5/ Only if earnings exceed 8 percent of original cost of plant in service or if discrimination between class of customers.
6/ Primarily Federal Energy Regulatory Commission jurisdiction.
7/ Commission jurisdiction excluded from rates for intrastate service covered by special agreements with municipalities and rates for intrastate services subject to the Federal Energy Regulatory Commission.
8/ Telephone is the only regulated utility.
9/ Municipal utilities exempt from state regulation.
10/ Authority limited to rate charged and manner of delivery.
11/ Intercommunity natural gas association (owned by 2 or more municipals) should be answered same as private gas utilities.
12/ Only when service extends beyond the corporate limits of a publicly owned utility company.
13/ The Railroad Commission of Texas has safety jurisdiction over these utilities outside the corporate limits of the city.
14/ Wyoming Supreme Court decision to effect that PSC cannot regulate gas sale for resale.

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wholesale rates, refers to the prices charged by natural gas suppliers on gas intended for resale. The first two columns of table A-2 indicate that 28 state commissions have authority to regulate wholesale rates for gas sales to public authorities by privately-owned companies. Only 13 states that have publicly-owned gas utilities regulate the wholesale rates of these public companies on sales for resale made to public authorities. Maine and Oregon have no publicly-owned gas utilities.

Columns 3 and 4 of table A-2 indicate that 31 state commissions have authority to regulate wholesale rates charged to the U.S. government by investor-owned gas companies, while only 12 states have authority to regulate their wholesale rates charged by publicly-owned gas companies to the Federal government. Columns 5 and 6 show that 31 state commissions have authority to regulate wholesale rates charged for sales to privately-owned gas companies for sales by private gas companies, while only 12 state commissions have authority to regulate sales by publicly-owned gas companies. Sales to publicly-owned companies are subject to rate regulation in 27 states when the vendor is a private company. This figure declines to 12 states when the vendor is a publicly-owned company.

More than half of the state public utility commissions regulate rates for gas transmission on account of others. Gas transmission on account of others concerns transmission by companies under state jurisdiction to ultimate end users. Table A-3 presents the listing of state agencies' authority to regulate rates for gas transmission on account of others by privately-owned and publicly-owned companies. As shown by table A-3, 21 state agencies regulate rates for transmission for neither privately-owned

TABLE A-3

STATE AGENCY AUTHORITY TO REGULATE RATES FOR GAS TRANSMISSION ON ACCOUNT OF OTHERS BY STATE, 1979

Column Agency	(1) Regulation of Rates for Transmission by a Privately-Owned Company	(2) Regulation of Rates for Transmission by a Publicly-Owned Company
Alabama	Y	N
Alaska	Y	Y
Arizona	Y	N
Arkansas	N	N
California	Y	N
Colorado	Y	Y 1/
Connecticut	N	N
Delaware	N	N
D.C.	N	N
Florida	N	N
Georgia	Y	N
Hawaii	N	N
Idaho	N	N
Illinois	Y	N
Indiana	N	N
Iowa	N	N
Kansas	Y	2/
Kentucky	Y	N
Louisiana	N	N
Maine	Y	Y 3/
Maryland	N	N
Massachusetts	Y	Y
Michigan	Y	N
Minnesota	N	N
Mississippi	N	N
Missouri	N	N
Montana	N	N
Nebraska 4/		
Nevada	Y	5/
New Hampshire	Y	N
New Jersey	Y	N
New Mexico	Y	6/
New York	Y	Y
North Carolina	N	N
North Dakota	N	N
Ohio	N	N
Oklahoma	Y	N
Oregon	N	N
Pennsylvania	Y	Y 7/
Rhode Island	Y	Y
South Carolina	Y	N
South Dakota	N	N
Tennessee	N	N
Texas 8/	Y	Y
Utah	Y	N
Vermont	Y	Y
Virginia	N	N
Washington	Y	N
West Virginia	Y	Y
Wisconsin	Y	Y
Wyoming	Y	Y 9/

Source: Paul Rodgers, 1979 Annual Report on Utility and Carrier Regulation of the National Association of Regulatory Utility Commissioners (Washington, D.C.:NARUC, 1980) pp. 392-7.

1/ Public utilities regulated when outside of municipal boundary only.
2/ Same as for private utilities and co-ops for facilities outside of 3 miles from the corporate limits of municipalities. Commission has no jurisdiction within the 3 mile limit.
3/ None in state.
4/ Telephone is the only regulated utility.
5/ Municipal utilities exempt from state regulation.
6/ Intercommunity natural gas association (owned by 2 or more municipals) should be answered same as private gas utilities.
7/ Only when service extends beyond the corporate limits of a publicly owned utility company.
8/ The Railroad Commission of Texas has safety jurisdiction over municipally owned gas utilities and appellate rate jurisdiction over these utilities outside the corporate limits of the city.
9/ Public utilities regulated insofar as they are owned and operated outside of corporate limits of the city.

or publicly-owned companies, while 11 state agencies have regulations for both types of companies. The remaining 18 states have certain qualifiers pertaining to their regulatory authority. These qualifiers are explained in the footnotes. In a categorical breakdown, 28 states have rate regulations for transmission by privately-owned companies, and 13 states have regulations for publicly-owned companies.

Most state utility commissions have the authority to initiate gas rate investigations and prescribe temporary rates. As shown in table A-4, all public utility commissions can initiate gas rate investigations of investor-owned gas companies,[1] while only 19 state commissions have the authority to initiate such inquiries of publicly-owned companies. Public utility commissions in 45 states can prescribe temporary rates for investor-owned gas utilities, while 17 state commissions can prescribe temporary rates for publicly-owned gas companies.

Most state public utility commissions have the authority to require prior authorization of gas rate charges and to suspend proposed rates filed by privately-owned utilities. As shown in table A-5, 47 state agencies have authority to require the prior authorization of gas rate charges by privately-owned companies, whereas only 18 state agencies have similar authority over publicly-owned companies. Forty-four state agencies have authority over privately-owned companies, and 15 state agencies have authority over publicly-owned companies in the suspension of proposed gas

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[1] Except Nebraska, which has no investor-owned companies.

TABLE A-4

STATE AGENCY AUTHORITY TO INITIATE GAS RATE INVESTIGATIONS AND PRESCRIBE TEMPORARY RATES BY STATE, 1979

Column Agency	(1) Agency's Own Motion Initiates Gas Rate Investigation of Private Companies	(2) Agency's Own Motion Initiates Gas Rate Investigation of Public Companies	(3) Authority to Prescribe Temporary Gas Rates Pending Investigation of Private Companies	(4) Authority to Prescribe Temporary Gas Rates Pending Investigation of Public Companies
Alabama	Y	N	Y	N
Alaska	Y	Y	Y	Y
Arizona	Y	N	Y	N
Arkansas	Y	N	Y	N
California	Y	N	Y 1/	N
Colorado	Y	Y 2/	Y 3/	Y 2/, 3/
Connecticut	Y	N	Y	N
Delaware	Y	N	Y	N
D.C.	Y	N	N	N
Florida	Y	N	Y	N
Georgia	Y	N	Y	N
Hawaii	Y	N	Y	N
Idaho	Y	N	Y	N
Illinois	Y	N	Y	N
Indiana	Y	Y	N	N
Iowa	Y	N	Y 4/	N
Kansas	Y	Y 5/	Y	5/
Kentucky	Y	N	Y	N
Louisiana	Y	N	Y	N
Maine	Y	Y 6/	Y	Y 6/
Maryland	Y	Y	Y	Y
Massachuentts	Y	Y	Y	Y
Michigan	Y	N	Y 7/	N
Minnesota	Y	8/	Y	N
Mississippi	Y	N	N	N
Missouri	Y	N	Y	N
Montana	Y	Y	Y	Y
Nebraska 9/	N	N	N	N
Nevada	Y	10/	N	10/
New Hampshire	Y	N	Y	N
New Jersey	Y	N	Y	N
New Mexico	Y	11/	Y	11/
New York	Y	N	Y	Y
North Carolina	Y	N	Y	N
North Dakota	Y	N	Y	N
Ohio	Y	N	Y	N
Oklahoma	Y	N	Y	N
Oregon	Y	13/	N	13/
Pennsylvania	Y	Y 14/	Y 12/	Y 14/
Rhode Island	Y	Y	Y	Y
South Carolina	Y	N	Y	N
South Dakota	Y	Y	Y	N
Tennessee	Y	N	Y	N
Texas 15/	Y	Y	Y	Y
Utah	Y	N	Y	N
Vermont	Y	Y	Y	Y
Virginia	Y	N	Y	N
Washington	Y	N	Y	N
West Virginia	Y	Y	Y	Y
Wisconsin	Y	Y	Y	Y
Wyoming	Y	Y 16/	Y	Y 16/

Source: Paul Rodgers, 1979 Annual Report on Utility and Carrier Regulation of the National Association of Regulatory Utility Commissioners (Washington, D.C.: NARUC, 1980) pp. 393-6.

1/ May fix temporary rates, but practice is not followed.
2/ Public utilities regulated when outside of municipal boundary only.
3/ No specific statutory authority.
4/ Application rates are temporary and are collected under bond subject to refund, from one to ninety days after suspension.
5/ Same as for private utilities and co-ops for facilities outside of 3 miles from the corporate limigs of municipalities. Commission has no jurisdiction within the 3 mile limit.
6/ None in state.
7/ Commission has authority to grant partial and immediate rate relief during pending of final order, after statutory requirements are met.
8/ Municipal utilities exempt from state regulation.
9/ Telephone is the only regulated utility.
10/ Municipal utilities exempt from state regulation.
11/ Intercommunity natural gas association (owned by 2 or more municipals) should be answered. Same as private utilities.
12/ Grant emergency increases only.
13/ None in state.
14/ Only when service extends beyond the corporate limits of a public, owned utility company.
15/ The Railroad Commission of Texas has safety jurisdiction over municipally owned gas utilities and appellate rate jurisdiction over these utilities outside the corporate limits of the city.
16/ Public utilities regulated in so far as they are owned and operated outside corporate limits.

TABLE A-5

STATE AGENCY AUTHORITY TO REQUIRE PRIOR AUTHORIZATION OF GAS RATE CHANGES AND TO SUSPEND PROPOSED RATE CHANGES

Column	(1)	(2)	(3)	(4)	(5)
Agency	Require Prior Authorization of Gas Rate Changes by Privately-Owned Companies	Require Prior Authorization of Gas Rate Changes by Publicly-Owned Companies	Suspend Porposed Gas Rate Changes by Privately-Owned Companies	Suspend Proposed Gas Rate Changes by Publicly-Owned Companies	Maximum Period of Rate Change Suspension
Alabama	Y	N	Y	N	6 months
Alaska	Y	Y	Y	Y	18 months
Arizona 1/					
Arkansas	N	N	Y	N	6 months
California	Y	N	Y	N	
Colorado	Y	Y 2/	Y	Y 2/	210 days
Connecticut	Y	N	Y	N	150 days
Delaware	Y	N	Y	N	Indefinite
D.C.	Y	N	Y	N	
Florida	Y	N	Y	N	8 months
Georgia	Y	N	Y	N	5 months
Hawaii	Y	N	N	N	Indefinite 3/
Idaho	Y	N	Y	N	6 months
Illinois	Y	N	Y	N	10 months
Indiana	Y	Y	Y	Y	
Iowa	Y	Y	Y	N	12 months
Kansas	Y	4/	Y	4/	Indefinite
Kentucky	Y	N	Y	N	5 months
Louisiana	Y	N	Y	N	No limit
Maine	Y	Y 5/	Y	Y 5/	8 months
Maryland	Y	Y	Y	Y	180 days
Massachusetts	Y	6/	Y	Y	6 months
Michigan	Y	N	7/	N	7/
Minnesota	Y	N	Y	8/	9 months
Mississippi	Y	N	Y	N	6 months
Missouri	Y	N	Y	N	10 months
Montana	Y	Y	Y	Y	9 months
Nebraska 9/					
Nevada	Y	10/	Y	10/	150 days
New Hampshire	Y	N	Y	N	6 months
New Jersey	Y	N	Y	N	8 months
New Mexico	Y	11/	Y	11/	9 months
New York	Y	Y	Y	Y	10 months
North Carolina	Y	N	Y	N	9 months
North Dakota	Y	N	Y	N	11 months
Ohio	Y	N	N	N	9 months
Oklahoma	Y	N	Y	N	No Limit
Oregon	Y	12/	Y	12/	10 months
Pennsylvania	Y	Y 13/	Y	Y 13/	9 months
Rhode Island	Y	Y	Y	Y	8 months
South Carolina	Y	N	Y	N	60 days
South Dakota	Y	N	Y	N	6 months
Tennessee	Y	N	Y	N	90 days 14/
Texas 15/	Y	Y	Y	Y	150 days
Utah	Y	N	Y	N	8 months
Vermont	Y	Y	Y	Y	6 months
Virginia	Y	N	Y	N	12 months
Washington	Y	N	Y	N	10 months
West Virginia	Y	Y	Y	Y	120 days
Wisconsin	Y	Y	16/	16/	16/
Wyoming	Y	Y 17/	Y	Y 17/	10 months

Source: Paul Rodgers, 1979 Annual Report on Utility and Carrier Regulation of the National Association of Regulatory Utility Commissioners (Washington, D.C.:NARUC, 1980) pp. 392-9.

1/ Rates cannot be increased without hearings and a subsequent order of the Commission, consequently, no suspension is required.
2/ Public utilities regulated when outside of municipal boundary only.
3/ Hawaii law provides that rate increases may not go into effect until approved by the Commission.
4/ Same as for private utilities and co-ops for facilities outside of 3 miles from the corporate limits of municipalities. Commission has no jurisdiction within the 3 mile limit.
5/ None in state.
6/ Required to advertise 30 days prior to change.
7/ Specific authority required to change rates. Rates do not become effective after a specified period, consequently, no suspension is required.
8/ Municipal utilities exempt from state regulation.
9/ Telephone is the only regulated utility.
10/ Municipal utilities exempt from state regulation.
11/ Intercommunity natural gas association (owned by 2 or more municipals)should be answered same as private gas utilities.
12/ None in state.
13/ Only when service extends beyond the corporate limits of a publicly owned utility company.
14/ 90 days at a time; up to a total of 6 months.
15/ The Railroad Commission of Texas has safety jurisdiction over municipally owned gas utilities and appellate rate jurisdiction over those utilities outside the corporate limits of the city.
16/ Specific authority required to change rates. Rates do not become effective after a specified period, consequently, no suspension is required.
17/ Public utilities regulated in so far as they are owned and operated outside corporate limits.

rate changes. The average amount of time for which a state agency may suspend rate charges is five and one-half months. Alaska allows the longest defined suspension period, eighteen months (the period for Hawaii is indefinite, and for Louisiana and Oklahoma the period has no limit). West Virginia has the shortest defined suspension period, four months.[1]

Most state public utility commissions have authority to require approval prior to the issuance of certain securities. Mortgage bonds are backed by specific assets of the utility. As shown in table A-6, the prior approval of mortgage bonds can be required by 44 state commissions. Debentures, which are general obligation bonds not secured by any claim or specific assets, might require approval prior to issuance in 43 states. Funds borrowed by the utility using notes with maturities greater than one year may require approval in 43 states prior to issuance. If these notes mature in less than one year, their approval by state commissions may be required in only 13 states. The sale of preferred and common stock might require approval by the public utility commission in 44 and 41 states, respectively. Approval of restricted stock options may be required in 36 states as indicated in the last column of table A-6.

Most state public utility commissions have the authority to require commission approval prior to major corporate transactions. Types of corporate transactions that may require prior state agency approval, and which are listed in table A-7, are sale and purchase of facilities, mergers or consolidations, security purchases of other utilities, purchase or

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[1] Special qualifications of these statements and of statements relating to other tables are listed in the footnotes of the tables.

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TABLE A-6

STATE AGENCY AUTHORITY TO REQUIRE APPROVAL PRIOR TO THE ISSUANCE OF SECURITIES BY TYPE OF SECURITY AND BY STATE, 1979

Column Agency	(1) Mortgage Bonds	(2) Debentures	(3) Notes Over One Year	(4) Notes Under One Year	(5) Preferred Stock	(6) The Underwriting of New Common Stock	(7) The Issuance of Restricted Stock Options
Alabama	Y	Y	Y	Y 1/	Y	Y	Y
Alaska	N	N	N	N	N	N	N
Arizona	Y	Y	Y	N	Y	Y	Y
Arkansas	Y	Y	Y	N	Y	Y	Y
California	Y	Y	Y	2/	Y	Y	Y
Colorado	Y	Y	Y	N	Y	Y	Y
Connecticut	Y	Y	Y	N	Y	Y	Y
Delaware	Y	Y	Y	N	Y	N	N
D.C.	Y	Y	Y	N	Y	Y	Y
Florida	Y	Y	Y	Y	Y	Y	Y
Georgia	Y	Y	Y	N	Y	Y	Y
Hawaii	Y	Y	Y	N	Y	Y	Y
Idaho	Y	Y	Y	Y	Y	Y	Y
Illinois	Y	Y	Y	N	Y	Y	Y
Indiana	Y	Y	Y	N	Y	Y	Y
Iowa	N	N	N	N	N	N	N
Kansas	Y	Y	Y	N	Y	Y	Y
Kentucky	Y	Y	Y	N	Y	Y	Y
Louisiana	Y	Y	Y	N	Y	Y	Y
Maine	Y	Y	Y	3/	Y	Y	Y
Maryland	Y	Y	Y	N	Y	N	Y
Massachusetts	Y	Y	Y	N	Y	Y	Y
Michigan	Y	Y	Y	N	Y	Y	Y
Minnesota	Y	Y	Y	Y	Y	Y	Y
Mississippi	N	N	N	N	N	N	N
Missouri	Y	Y	Y	N	Y	Y	Y
Montana	Y	Y	Y	Y	Y	Y	Y 4/
Nebraska 5/	N	N	N	N	N	N	N
Nevada	Y	Y	Y	Y	Y	Y	N
New Hampshire	Y	Y	Y	Y	Y	Y	Y
New Jersey	Y	Y	Y	N	Y	Y	Y
New Mexico	Y	Y	6/	N	Y	Y	N
New York	Y	Y	Y	N	Y	Y	Y
North Carolina	Y	Y	7/	N	Y	Y	Y
North Dakota	Y	Y	Y	N	Y	Y	Y
Ohio	Y	Y	Y	N	Y	Y	8/
Oklahoma	N	N	N	N	N	N	N
Oregon	Y	Y	Y	N	Y	Y	Y
Pennsylvania	Y	Y	Y	N	Y	Y	N
Rhode Island	Y	Y	Y	N	Y	Y	Y
South Carolina	Y	Y	Y	N	Y	Y	Y
South Dakota	Y 9/	N	N	Y 9/	Y 9/	N	N
Tennessee	Y	Y	Y	N	Y	Y	N
Texas	N	N	N	N	N	N	N
Utah	Y	Y	Y	Y	Y	Y	N
Vermont	Y	Y	Y	Y 10/	Y	Y	Y
Virginia	Y	Y	Y	N	Y	Y	N
Washington	Y	Y	Y	Y 11/	Y 11/	Y	Y
West Virginia	N	N	N	N	N	N	N
Wisconsin	Y	Y	Y	Y	Y	Y	Y
Wyoming	Y	Y	Y 12/	N	Y	Y	Y

Source: Paul Rodgers, 1979 Annual Report on Utility and Carrier Regulation of the National Association of Regulatory Utility Commissioners (Washington, D.C.;NARUC, 1980) pp.482-484.

1/ Approval required only if short-term exceeds 5% of total capitalization.
2/ "No" unless to refund other notes, the combined terms of which exceeds one year.
3/ "Yes" if utility subject to Federal Power Act and notes exceed five percent limitations.
4/ Interim approval.
5/ If new stock issued.
6/ No Commission regulation of electric or gas utilities.
7/ Notes under 18 months require no approval. Over 18 months require approval.
8/ Commission requires approval to issue notes in excess of two year maturity.
9/ If new issue of stock is involved, the plan must be approved.
10/ Black Hills Power Light Company only.
11/ If short-term debt exceeds 20% of assets. 30 V.S.A. section 108.
12/ When combined terms of original and refunding notes exceed 12 months or the proposed notes together with outstanding notes exceed 5% of total capitalization of a utility subject to regulation by the FERC. Over 18 months.

TABLE A-7

STATE AGENCY AUTHORITY TO REQUIRE APPROVAL PRIOR TO CORPORATE TRANSACTIONS BY TYPE OF TRANSACTION AND BY STATE, 1979

Column Agency	(1) Sale of Facilities (Entire Operating Units)	(2) Purchase of Facilities (Entire Operating Units)	(3) Merger or Consolidation	(4) Purchase of Securities of Other utilities	(5) Purchase or Issuance of Securities by Utilities Operating in One State but Incorporated in Another	(6) Entrance Into Lease Transactions
Alabama	Y	Y	Y	Y	Y	Y
Alaska	Y	Y	Y	N	N	Y
Arizona	Y	Y	Y	Y	Y	N
Arkansas	Y	Y	Y	Y	Y	Y
California	Y	Y	Y	Y	Y	1/
Colorado	Y	Y	Y	N	Y	N
Connecticut	Y	Y	Y	Y	Y	Y
Delaware	Y	N	Y	N	Y	N
D.C.	N	N	Y	Y	Y	N
Florida	N	N	N	N	Y	N
Georgia	Y	Y	Y	N	Y	Y
Hawaii	Y	Y	Y	Y	Y	Y
Idaho	Y	Y	Y	N	Y	N
Illinois	Y	Y	Y	Y	Y	Y
Indiana	Y 2/	Y 3/	Y	Y	Y	Y
Iowa	Y	Y	Y	N	N	N
Kansas	Y	Y	Y	Y	Y	N
Kentucky	Y	Y	Y	N	Y	N
Louisiana	Y	Y	Y	Y	N	N
Maine	Y	Y	Y	Y	Y	Y
Maryland	Y	Y	Y	N	N	Y
Massachusetts	Y	Y	Y	Y	N	N
Michigan	N	N	Y	N	Y	Y
Minnesota	Y	Y	Y	Y	Y	Y
Mississippi	Y	Y	Y	N	N	N
Missouri	Y	Y	Y	Y	Y	Y
Montana	N	N	N	N	Y	N
Nebraska 4/	N	N	N	N	N	N
Nevada	N	N	Y	N	N	N
New Hampshire	Y	Y	Y	Y	Y	N
New Jersey	Y	Y	Y	Y	Y	5/
New Mexico	Y	Y	Y	Y	Y	N
New York	Y	Y	Y	Y	Y	Y
North Carolina	Y	Y	Y	Y	Y	Y
North Dakota	Y	Y	Y	Y	Y	6/
Ohio	Y	Y	Y	Y	Y	7/
Oklahoma	Y	Y	Y	N	N	N
Oregon	Y	16/	Y	Y	Y	Y
Pennsylvania	Y	Y	Y	Y	Y	Y
Rhode Island	Y	Y	Y	Y 8/	9/	10/
South Carolina	Y	Y	Y	Y	Y	Y
South Dakota	N	N	N	N	N	Y 11/
Tennessee	Y	Y	Y	N	Y	Y
Texas	Y	Y	Y	Y	N	N
Utah	Y	Y	Y	Y	Y	Y 12/
Vermont	Y	Y	Y	Y	Y	Y
Virginia	Y	Y	Y	Y	N	Y
Washington	Y 13/	Y 14/	Y	Y	Y	Y 15/
West Virginia	Y	Y	Y	Y	N	Y
Wisconsin	Y	Y	Y	Y	N	Y
Wyoming	Y	Y	Y	N	Y	Y

Source: Paul Rodgers, 1979 Annual Report on Utility and Carrier Regulation of the National Association of Regulatory Utility Commissioners (Washington, D.C: NARUC, 1980) pp. 482,484.

1/ "Yes," as lessor of operating unit.
2/ To a public utility.
3/ For a public utility.
4/ No Commission regulation of electric or gas utilities.
5/ Major units of property.
6/ Matter has yet to appear.
7/ Depends on particular transaction.
8/ Purchase of stock requires approval.
9/ No approval necessary for issuance of securities.
10/ Among utilities only.
11/ Black Hills Power Light Company only.
12/ Applies if lease is between two utilities engaged in the same general line of business in the state.
13/ When used in utility service.
14/ From other utilities.
15/ When leases are with affiliated interest.
16/ From another utility.

issuance by utilities operating in one state but incorporated in another, and entrance into lease transactions. Forty-four state agencies have the authority to require approval prior to the sale of facilities, and 43 state agencies have the authority to require prior approval for the purchase of facilities. Forty-seven state commissions have the authority to require prior approval of mergers and acquisitions. Thirty-three states may require prior approval regarding the purchase of securities of other utilities. Thirty-six states have authority to require prior approval for the purchase of securities by utilities operating in one state, but incorporated in another, while 37 states have authority to require prior approval for the issuance of securities by utilities operating in one state but incorporated in another. Thirty-one states have the authority to require prior approval for corporate transactions dealing with entrance into lease agreements, but such authority may be limited as described in the footnotes of table A-7.

Most state public utility commissions have the authority to regulate safety standards for gas, particularly if the gas is sold by privately-owned companies. Table A-8 sets forth a listing of the authority state agencies have in regulating safety standards. These standards relate to BTU content of gas sold, pressure of gas sold, and gas safety for gas sold by privately-owned and publicly-owned companies. Fifteen state agencies have established standards for safety regulation in all six categories. Two states, Minnesota and Nebraska, have not established gas safety standards. In a category-by-category breakdown, the following results become evident. Forty-seven states have established standards for BTU content of gas sold by privately-owned companies, whereas seventeen states have set BTU standards for publicly-owned companies (Michigan has no

TABLE A-8

STATE AGENCIES WITH AUTHORITY TO REGULATE SAFETY STANDARDS FOR GAS BY STATE, 1979

Column Agency	(1) BTU Content of Gas Sold by Privately-Owned Companies	(2) BTU Content of Gas Sold by Publicly-Owned Companies	(3) Pressure of Gas Sold by Privately-Owned Companies	(4) Pressure of Gas Sold by Publicly-Owned Companies	(5) Gas Safety for Gas Sold by Privately-Owned Companies	(6) Gas Safety for Gas Sold by Publicly-Owned Companies
Alabama	Y	N	Y	N	Y	Y
Alaska	Y	Y	Y	Y	Y	Y
Arizona	Y	N	Y	N	Y	Y
Arkansas	Y	N	Y	Y	Y	Y
California	Y	N	Y	N	Y	N
Colorado 1/	Y	Y	Y	Y	Y	Y
Connecticut	Y	N	Y	N	Y	Y
Delaware	N	N	N	N	Y	N
D.C.	Y	N	Y	N	Y	N
Florida	Y	N	Y	N	Y	Y
Georgia	Y	N	Y	N	Y	N
Hawaii	Y	N	Y	N	Y	N
Idaho	Y	N	Y	N	Y	N
Illinois	Y	N	Y	Y	Y	Y
Indiana	Y	Y	Y	Y	Y	Y
Iowa	Y	Y	Y	Y	Y	Y
Kansas	Y	Y 2/	Y	Y 2/	Y	Y
Kentucky	Y	N	Y	N	Y	N
Louisiana	Y	N	Y	N	Y	N
Maine	Y	Y	Y	Y	Y	Y
Maryland	Y	Y	Y	Y	Y	Y
Massachusetts	Y	Y	Y	Y	Y	Y
Michigan	Y	3/	Y	3/	Y	3/
Minnesota	N	N	N	N	N	N
Mississippi	N	N	N	N	Y	Y
Missouri	Y	N	Y	N	Y	Y
Montana	Y	Y	Y	Y	Y	Y
Nebraska	N	N	N	N	N	N
Nevada	Y	Y	Y	N	Y	N
New Hampshire	Y	N	Y	N	Y	N
New Jersey	Y	Y 4/	Y	Y 4/	Y	Y 4/
New Mexico	Y	N	Y	N	Y	N
New York	Y	Y	Y	Y	Y	Y
North Carolina	Y	N	Y	N	Y	Y
North Dakota	Y	N	Y	N	Y	Y
Ohio	Y	N	Y 5/	N	Y	N
Oklahoma	Y	N	Y	N	Y	N
Oregon	Y	N	Y	N	Y	Y
Pennsylvania	Y	N	Y	N	Y	N
Rhode Island	Y	N	Y	Y	Y	Y
South Carolina	Y	N	Y	Y	Y	Y
South Dakota	Y	N	Y	N	Y	N
Tennessee	Y	N	Y	N	Y	Y
Texas	Y	Y	Y	Y	Y	Y
Utah	Y	N	Y	N	Y	N
Vermont	Y	Y	Y	N	Y	6/
Virginia	Y	N	Y	N	Y	N
Washington	Y	N	Y	N	Y	Y
West Virginia	Y	Y	Y	Y	Y	Y
Wisconsin	Y	Y	Y,	Y	Y	Y
Wyoming	Y	Y	Y 7/	Y 7/	Y 7/	Y 7/

SOURCE: Paul Rodgers, 1979 Annual Report on Utility and Carrier Regulation of the National Association of Regulatory Utility Commissioners (Washington, D.C.: NARUC, 1980), pp. 496, 497, 499.

1/ Colorado Public Utilities Commission has no jurisdiction over publicly-owned (municipal)utilities inside corporate limits, except for gas safety. Public Utilities regulated outside of municipal boundary only.
2/ Same as for private utilities and cooperatives for facilities outside of 3 miles from the corporate limit of municipalities—Commission has no jurisdiction within the 3 mile limit.
3/ There are no public gas utilities in Michigan.
4/ However, there are no public gas suppliers within the state.
5/ DOT gas safety standards now apply.
6/ Have authority, but there are no gas public companies operating in Vermont.
7/ DOT gas safety standards now apply.

public gas utilities). In the establishment of standards for pressure of gas sold by privately-owned and publicly-owned companies, the numbers of states having standards set are 47 and 19, respectively. The final categories, establishment of standards for gas safety for gas sold by privately-owned and publicly-owned companies show affirmative responses for 49 and 29 state agencies, respectively. Indicators point to the fact that there are more safety standards established for privately-owned than publicly-owned companies by state agencies.

Most state public utility commissions have authority to regulate the adequacy of gas service of privately-owned companies. Fewer state public utility commission regulate the adequacy of service of publicly-owned companies. Adequacy of gas service concerns state agency authority to authorize and to regulate gas interconnections between privately-owned companies and between publicly-owned companies and state agency authority to test meters or set standards for accuracy of meters of privately-owned and publicly-owned companies. As shown in table A-9, state agencies have less authority over publicly-owned companies than they do over privately-owned companies. Thirty-nine state agencies have authority to authorize gas interconnections by privately-owned companies, whereas 16 state agencies have no authority to authorize gas interconnections by publicly-owned companies. In the area of state agency authority to require gas interconnections, a larger number of state agencies responded negatively in both privately-owned and publicly-owned categories. Twenty-eight state agencies have authority over privately-owned companies, and eleven state agencies have authority over publicly-owned companies to require gas interconnections by the utilities. State agencies are more

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TABLE A-9

STATE AGENCIES WITH AUTHORITY TO REGULATE ADEQUACY OF GAS SERVICE BY STATE, 1979

Column Agency	(1) Authorize Gas Interconnections by Privately-Owned Companies	(2) Authorize Gas Interconnections by Publicly-Owned Companies	(3) Require Gas Interconnections by Privately-Owned Companies	(4) Require Gas Interconnections by Publicly-Owned Companies	(5) Test Meters or Set Standards for Accuracy of Meters of Privately-Owned Companied	(6) Test Meters or Set Standards for Accuracy for Meters of Publicly-Owned Companies
Alabama	Y	N	Y	N	Y	N
Alaska	Y	Y	Y	Y	Y	Y
Arizona	Y	N	Y	N	Y	N
Arkansas	N	N	N	N	Y	N
California	Y	N	Y	N	Y	N
Colorado 1/	Y	Y	Y	Y	Y	Y
Connecticut	N	N	N	N	Y	N
Delaware	Y	N	N	N	Y	N
D.C.	N	N	N	N	Y	N
Florida	Y	N	Y	N	Y	N
Georgia	N	N	N	N	Y	N
Hawaii	N	N	N	N	Y	N
Idaho	N	N	N	N	Y	N
Illinois	Y	N	Y	N	Y	N
Indiana	N	N	N	N	Y	Y
Iowa	Y	Y	2/	2/	Y	Y
Kansas	Y	Y 3/	Y	Y 3/	Y	Y 3/
Kentucky	Y	N	Y	N	Y	N
Louisiana	Y	N	Y	N	Y	N
Maine	Y	Y	Y	Y	Y	Y
Maryland	Y	Y	Y	Y	Y	Y
Massachusetts	Y	Y	Y	N	Y	Y
Michigan	Y	4/	N	4/	Y	4/
Minnesota	N	N	N	N	Y	N
Mississippi	Y	Y	N	N	Y	Y
Missouri	Y	N	N	N	Y	N
Montana	N	N	N	N	Y	Y
Nebraska	N	N	N	N	N	N
Nevada	Y	N	Y	N	Y	N
New Hampshire	Y	N	N	N	Y	N
New Jersey	Y	Y 5/	Y	Y 5/	Y	Y 5/
New Mexico	Y	N	Y	N	Y	N
New York	Y	Y	Y	Y	Y	Y
North Carolina	Y	N	Y	N	Y	N
North Dakota	Y	N	N	N	Y	N
Ohio	Y	N	N	N	Y	N
Oklahoma	Y	N	Y	N	Y	N
Oregon	Y	Y	Y	Y	Y	N
Pennsylvania	N	N	N	N	Y	N
Rhode Island	Y	N	N	N	Y	Y
South Carolina	Y	N	Y	N	Y	N
South Dakota	Y	N	Y	N	Y	N
Tennessee	N	N	N	N	Y	N
Texas	Y	Y	Y	Y	Y	Y
Utah	Y	N	Y	N	Y	N
Vermont	Y	6/	Y	6/	Y	Y
Virginia	Y	N	Y	N	Y	N
Washington	Y	Y	N	N	Y	N
West Virginia	Y	Y	N	N	Y	Y
Wisconsin	Y	Y	Y	Y	Y	Y
Wyoming	Y	Y 7/	Y	Y 7/	Y	Y 7/

Source: Paul Rodgers, 1979 Annual Report on Utility and Carrier Regulation of the NationalAssociation of Regulatory Utility Commissioners (Washington, D.C: NARUC, 1980) pp. 496-497, 499.

1/ Colorado Public Utilities Commission has no jurisdiction over publicly-owned (municipal) utilities inside corporate limits, except for gas safety. Public utilities regulated when outside of municipal boundary only.
2/ This commission may after hearing require these things, not a blanket requirements.
3/ Same as for private utilities and cooperatives for facilities outside of 3 miles from the corporate limit of municipalities--Commission has no jurisdiction within the 3 mile limit.
4/ There are no public gas utilities in Michigan.
5/ However, there are no public gas suppliers within the state.
6/ Have authority, but there are no gas public companies operating in Vermont.
7/ Commission regulates municipal utilities outside corporate limits.

stringent with privately-owned companies in relation to the authority to test meters or set accuracy standards of meters than they are with publicly-owned companies. Only one state agency, Nebraska, has no authority over privately-owned companies, whereas 18 state agencies have authority over publicly-owned companies in relation to the testing and standard setting of meters.

Except for the construction of gas transmission lines by privately-owned companies, less than one-half of the state agencies have authority to require certification in the other major construction addition categories. The authority to require certificates of convenience and necessity for construction of major additions by state agencies is presented in table A-10. The major addition categories listed in this table are construction of gas generating plant, transmission and distribution lines, and other plant by privately-owned and publicly-owned companies. Table A-10 indicates that 21 state agencies have authority to require convenience and necessity certificates for the construction of gas generating plants by privately-owned companies, and even fewer state agencies have the authority over publicly-owned companies in this category. The state agency certification authority over gas transmission line construction by privately-owned companies is the most regulated of all these categories with 28 states having such authority. However, for publicly-owned companies in this category, only 15 state agencies have convenience and necessity certification requirement authority. In the construction of gas distribution lines by privately-owned companies, half the state agencies, 25, have certification authority. Thirteen state agencies have authority over publicly-owned companies in this category. For the construction

TABLE A-10

STATE AGENCY AUTHORITY TO REQUIRE CERTIFICATES OF CONVENIENCE AND NECESSITY FOR CONSTRUCTING MAJOR ADDITIONS BY STATE, 1979

Column	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Agency	Construction of Gas Generating Plant by Privately-Owned Companies	Construction of Gas Generating Plant by Publicly-Owned Companies	Construction of Gas Transmission Lines by Privately-Owned Companies	Construction of Gas Transmission Lines by Publicly-Owned Companies	Construction of Gas Distribution Lines by Privately-Owned Companies	Construction of Gas Distribution Lines by Publicly-Owned Companies	Construction of Other Plant by Privately-Owned Companies	Construction of Other Plant by Privately-Owned Companies
Alabama	N	N	Y	N	N	N	Y	N
Alaska	Y	Y	Y	Y	Y	Y	Y	Y
Arizona	N	N	N	N	N	N	N	N
Arkansas	N	N	Y	N	N	N	Y	N
California	N	N	N	N	N	N	N	N
Colorado 1/	2/	2/	2/	2/	2/	2/	2/	2/
Connecticut	3/	3/	3/	3/	3/	3/	3/	3/
Delaware	N	N	N	N	N	N	N	N
D.C.	N	N	N	N	N	N	N	N
Florida	N	N	N	N	N	N	N	N
Georgia	N	N	Y	N	Y	N	N	N
Hawaii	4/	N	4/	N	4/	N	4/	N
Idaho	N	N	Y	N	Y	N	Y	N
Illinois	Y	N	Y	N	Y	N	Y	N
Indiana	N	N	N	N	N	N	N	N
Iowa	N	N	Y	N	Y	Y	N	N
Kansas	N	N	N	N	N	N	N	N
Kentucky	Y	N	Y	N	Y	N	Y	N
Louisiana	N	N	N	N	N	N	N	N
Maine	N	N	N	N	N	N	N	N
Maryland	N	N	N	N	N	N	N	N
Massachusetts	N	N	Y 5/	Y 5/	N	N	N	N
Michigan	N	N	Y	N	N	N	Y	N
Minnesota	N	N	N	N	N	N	N	N
Mississippi	Y	Y	Y	Y	Y	Y	Y	N
Missouri	Y	N	Y	N	Y	N	Y	N
Montana 6/	N	N	N	N	N	N	N	N
Nebraska	N	N	N	N	N	N	N	N
Nevada	Y	N	Y	N	Y	N	N	N
New Hampshire	N	N	N	N	N	N	N	N
New Jersey 7/								
New Mexico	Y	N	Y	N	8/	8/	8/	8/
New York	N	N	Y	Y	9/	9/, 10/	9/	9/, 10/
North Carolina	N	N	N	N	N	N	N	N
North Dakota	Y	Y	Y	Y	Y	N	N	N
Ohio	11/	11/	11/	11/	N	N	N	N
Oklahoma	N	N	N	N	N	N	N	N
Oregon	N	N	N	N	N	N	N	N
Pennsylvania	N	N	N	N	Y	N	N	N
Rhode Island	Y	Y	Y	Y	Y	Y	Y	Y
South Carolina	N	N	N	N	Y	N	Y	N
South Dakota	N	N	N	N	N	N	N	N
Tennessee 12/	Y	N	Y	N	Y	N	Y	N
Texas	N	N	N	N	N	N	N	N
Utah	Y	N	N	N	N	N	N	N
Vermont	Y	N	Y	13/	Y	N	Y 14/	Y 14/
Virginia 15/	Y	N	Y	N	Y	N	N	N
Washington	N	N	N	N	N	N	N	N
West Virginia	Y	Y	Y	Y	Y	Y	Y	Y
Wisconsin	Y	Y	Y	Y	Y	Y	Y	Y
Wyoming	Y	Y	Y	Y	Y	Y	Y	Y

Source: Paul Rodgers, 1979 Annual Report on Utility and Carrier Regulation of the National Association of Regulatory Utility Commissioners (Washington, D.C.:NARUC, 1980) pp. 505-509.

1/ Colorado Public Utilities Commission has no jurisdiction over municipally owned utilities operating inside corporate limits except as to gas safety.

2/ Not necessary to obtain certificate for extension of its line, plant or system if contiguous to its existing system and if such extension is not into area of another utility of like character, and if extension is necessary in the ordinary course of its business.

3/ Participates through membership on Power Facilities Evaluation Council which has authority indicated.

4/ Although certification is not required, all capital expenditures in excess of $500,000 or 10 percent of the total plant in service must be submitted to the commission for review.

5/ Department has power to rezone property for construction of utility facilities and make takings in Eminent Domain Proceedings.

6/ Certificates, Permits, and Licenses - None in Montana.

7/ The key word here is authority. The commission can do all these things on the basis that utilities must provide safe, adequate and proper service.

8/ Certificate needed for extensions into new territory not contiguous to existing service of being served by another utility.

9/ The certificates of public convenience and necessity heretofore issued by the commission for the most part authorize construction of minor electric, gas and telephone plant of all sorts, without time limit, within specified municipalities. Therefore, the utility needs no additional certificate, other than for a major steam electric generating facility under Public Service Law, Article 8, and a transmission line under Public Service Law, Article 7, to construct additional plant within its previously certified area. A certificate is required, however, before a utility may construct paint of any sort outside its previously certified area. In 1972 the State's Public Service Law was amended to establish within the Department of Public Service a Board on Electric Generation Siting and the Environment, intended to have one-stop siting jurisdiction. The Chairman of the Public Service Commission acts as Chairman of the Board. The other members are the Commissioners of Environmental Conservation, Health and Commerce, and an ad hoc member appointed by the Governor, who shall be a resident of the judicial district in which the facility as primarily proposed is to be located. The Commissioner of Health now participates in pending Article VIII cases only. The State Legislature amended Article VIII of the Public Service Law in 1978; pursuant to that amendment, the Commissioner of the New York State Energy Office participates in new Article VIII cases (in lieu of the Commissioner of Health).

10/ "No", except for service outside the municipality. General Municipal Law, Sec. 361, 364; Public Service Law, Sec. 68.

11/ Participates through membership on Power Siting Commission, which has authority as indicated.

12/ The term "certificate of convenience and necessity" does not apply for construction, but the agency does approve major additions of all regulated utilities.

13/ Have authority, but no public gas companies in Vermont.

14/ If significant environmental impact.

15/ The key word here is authority. The commission can do all these things on the basis that utilities must provide safe, adequate, and proper service.

of other plant, 21 state agencies have authority over privately-owned companies, and 10 state agencies have authority over publicly-owned companies to require certification of convenience and necessity.

Twenty-two states have no authority to require certification in any of the eight categories listed in table A-10. Five states, Alaska, Mississippi, Rhode Island, Wisconsin, and Wyoming, have authority to require certification in all eight categories. New Jersey has broad authority to regulate in many areas. This authority stems from the agency's mandate to ensure safe, adequate and proper service by the utilities.

Most state public utility commissions have the authority to require privately-owned utilities to acquire a certification of convenience and necessity to initiate new gas service or to abandon gas service. Table A-11 shows that 37 state agencies have authority to require certification of privately-owned companies for initiating gas service; whereas 13 states have authority over publicly-owned companies in this category. Thirty-seven state agencies have authority to require certification of abandonment of gas facilities or services by privately-owned companies, and 12 states have similar authority over publicly-owned companies.

Overall, six state agencies have no authority to require certification for initiating or abandoning gas services or facilities by either privately- or publicly-owned companies. Six state agencies have authority in all of these areas. The New Jersey agency has a broad mandate that gives it the authority to ensure safe, adequate, and proper service by the utilities.

TABLE A-11

STATE AGENCY AUTHORITY TO REQUIRE CERTIFICATES OF CONVENIENCE AND NECESSITY FOR INITIATING GAS SERVICE AND ABANDONING SERVICE AND FACILITIES BY STATE, 1979

Column Agency	(1) Initiating Gas Service by Privately-Owned Company	(2) Initiating Gas Service by Publicly-Owned Company	(3) Abandonment of Gas Facilities or Services by Privately-Owned Company	(4) Abandonment of Gas Facilities or Services by Publicly-Owned Company
Alabama	Y	N	Y	N
Alaska	Y	Y	Y	Y
Arizona	Y	N	Y	N
Arkansas	Y	N	Y	N
California	Y	N	Y	N
Colorado 1/	Y	Y	Y	Y
Connecticut	N	N	N	N
Delaware	Y	N	Y	N
D.C.	N	N	N	N
Florida	N	N	N	N
Georgia	Y	N	Y	N
Hawaii	N	N	N	N
Idaho	Y	N	Y	N
Illinois	Y	N	Y	N
Indiana	N	N	Y	N
Iowa	N	N	Y	?
Kansas	Y	2/	Y	2/
Kentucky	Y	N	Y	N
Louisiana 3/	N	N	N	N
Maine	Y 4/	Y 4/	5/	5/
Maryland	Y 6/	Y 6/	N	N
Massachusetts	N	N	Y	Y
Michigan	7/	N	Y	N
Minnesota	Y	N	N	N
Mississippi	Y	Y	Y	Y
Missouri	Y	N	Y	N
Montana 8/	N	N	Y	Y
Nebraska	N	N	N	N
Nevada	Y	N	Y	N
New Hampshire	Y	N	Y	N
New Jersey 9/				
New Mexico	Y	N	Y	N
New York	Y	10/	Y	Y
North Carolina	Y	N	Y	N
North Dakota	Y	N	Y	N
Ohio	N	N	Y 11/	N
Oklahoma	N	N	Y	N
Oregon	N	N	N	N
Pennsylvania	Y	N	Y	N
Rhode Island	Y	Y	N	N
South Carolina	Y	N	Y	N
South Dakota	Y	N	Y	N
Tennessee	Y	N	Y	N
Texas	N	N	Y	Y
Utah	Y	N	Y	N
Vermont	Y	N	Y	N
Virginia 12/	Y	N	N	N
Washington	Y	Y	N	N
West Virginia	Y	Y	Y	Y
Wisconsin	Y	Y	Y	Y
Wyoming	Y	Y	Y	Y

Source: Paul Rodgers, _1979 Annual Report on Utility and Carrier Regulation of the National Association of Regulatory Utility Commissioners_ (Washington, D.C.: NARUC, 1980) pp. 504-509.

1/ Colorado Public Utilities Commission has no jurisdiction over municipally owned utilities operating outside corporate limits except as to gas safety.

2/ Same as for private utilities and cooperatives for facilities outside of 3 miles from the corporate limits of municipalities—Commission has no jurisdiction within the 3 mile limit.

3/ Louisiana Constitution of 1974 grants wide and plenary authority to "regulate" but no specific certification authority is provided except by statute to radio common carriers. Authority may be implied.

4/ Finding of public convenience and necessity required if another utility is already offered or is authorized to offer a comparable service in the same area. 35 M.R.S.A. 13-A.

5/ 35 M.R.S.A., Sec. 212.

6/ Authorize exercise of franchise rather than issue certificate of Public Convenience and Necessity.

7/ Present certificate authority limited to gas transmission pipelines, gas storage fields, and to situations where one utility proposes to extend service from another utility.

8/ Certificates, Permits, and Licenses - None in Montana.

9/ The key word here is authority. The commission can do all these things on the basis that utilities must provide safe, adequate, and proper service.

10/ "No", except for service outside the municipality. _General Municipal Law_, Sec. 361, 164; _Public Service Law_, Sec. 68.

11/ Limited Authority.

12/ The key word here is authority. The commission can do all these things on the basis that utilities must provide safe, adequate, and proper service.

A large number of gas utilities and gas pipelines are under agency jurisdiction. Table A-12 shows there are 1,328 privately-owned and 1,064 publicly-owned utilities operating within state jurisdictions. Texas contains the largest number of privately-owned utilities (325), and Florida contains the largest number of publicly-owned utilities (111). On the average, each jurisdiction contains 26 privately-owned and 21 publicly-owned utilities. Hawaii and the District of Columbia have the least number of privately-owned utilities, 1 each, and 16 agencies have no publicly-owned utilities.

There are 936 privately-owned gas pipeline companies and 400 publicly-owned pipeline companies under state agency jurisdiction. Texas contains the largest number of privately-owned gas pipeline companies (325), and Florida contains the largest number of publicly-owned gas pipeline companies (111), with Texas second to Florida in the publicly-owned category (84). The average number of privately-owned and publicly-owned gas pipeline companies under agency jurisdiction are 18 and 8, respectively. The Nebraska commission is the one agency with neither privately-owned or publicly-owned gas pipeline companies under its jurisdiction. Only one state, Nebraska, regulates no privately-owned companies, and 33 states regulate no publicly-owned gas pipeline companies.

Most state public utility commissions have the authority to prescribe regulations concerning shortfalls and curtailments of gas service. In table A-13, columns one and two show that 27 state commissions have prescribed emergency regulations for gas outages, and 37 commissions have regulations dealing with gas curtailment. Columns three and four of table A-13 indicate that 46 public utility commissions have authority to

TABLE A-12

NUMBER OF GAS UTILITIES OPERATING WITHIN EACH STATE AND THE NUMBER OF GAS PIPELINE COMPANIES UNDER AGENCY JURISDICTION, 1979

Column Agency	(1) Number of Privately-Owned Utilities Operating in the State	(2) Number of Publicly-Owned Utilities Operating in the State	(3) Number of Privately-Owned Gas Pipeline Companies Under Agency Jurisdiction	(4) Number of Publicly-Owned Gas Pipeline Companies Under Agency Jurisdiction
Alabama	4	103	4	0
Alaska	4	1	4	0
Arizona	10	5	10	0
Arkansas	7	15	7	15 6/
California	7	3 1/	7	0
Colorado	10	10	10	2
Connecticut	5	1	5	0
Delaware	3	0	3	0
D.C.	1	0	1	0
Florida	14	111	14	111 6/
Georgia	4	89	4	28
Hawaii	1	0	1	0
Idaho	2	0	2	0
Illinois	19 2/	66	11	0
Indiana	26	20	26	20
Iowa	11	41	11	41 7/
Kansas	26	64	26	28
Kentucky	45	43	45	0
Louisiana	42	97	42	0
Maine	2	0	2	0
Maryland	10	1	10	1
Massachusetts	14	4	14	4
Michigan	10	0	10	0
Minnesota	13 3/	16	13 8/	16 8/
Mississippi	9	46	9	19 9/
Missouri	14	33	14	33
Montana	13	2	13	2
Nebraska	4/	10	0	0
Nevada	3	0	3	0
New Hampshire	7	0	7	0
New Jersey	4	0	4	0
New Mexico	6	10	6	4/
New York	24 5/	2	20 10/	2
North Carolina	5	8	5	0
North Dakota	4	3	4	0
Ohio	28	4/	28	0
Oklahoma	42	36	42	0
Oregon	3	0	3	0
Pennsylvania	43	0	43	0
Rhode Island	5	0	5	0
South Carolina	6	15	6	0
South Dakota	4	1	4	0
Tennessee	7	93	7	0
Texas	325	84	325	84 6/
Utah	4	0	4	0
Vermont	5	0	5	0
Virginia	14	3	14	0
Washington	4	3	4	3 11/
West Virginia	41	0	41	0
Wisconsin	16	1	16	1
Wyoming	22	0	22	0

Source: Paul Rodgers, 1979 Annual Report on Utility and Carrier Regulation of the National Association of Regulatory Utility Commissioners (Washington, D.C.: NARUC, 1980) pp. 387, 389-391.

1/ Not regulated by the California Public Utilities Commission.
2/ Includes eight combination electric and gas companies.
3/ Includes two combination electric and gas companies.
4/ Not Available.
5/ Includes seven combination electric and gas companies. Also four small private gas concerns have their own local production and sell to themselves and one or two other customers.
6/ Pipeline safety only.
7/ Service regulation only, not rates.
8/ Gas regulation established April 12, 1974; rate regulation became effective January 1, 1975.
9/ Municipal-13; District-1.
10/ Includes seven combination electric and gas companies.
11/ Certification and safety only.

TABLE A-13

STATE AGENCY REGULATION OF GAS UTILITIES DURING SHORTFALLS AND CURTAILMENTS OF GAS SERVICE, 1979

Column Agency	(1) The Agency has prescribed emergency regulation during outages	(2) The Agency has prescribed emergency regulation during curtailments	(3) The Agency has authority to establish priorities for customers classes served by private companies	(4) The Agency has authority to establish priorities for customers classes served by public companies	(5) The Agency has established standards for attaching new customers during shortages
Alabama	N	Y	Y	N	N
Alaska	Y	Y	N	N	Y
Arizona	Y,	N	Y	N	Y
Arkansas	N	Y	Y	N	N
California	Y 1/	Y 1/	Y	N	Y
Colorado	N	N	Y	4/	Y
Connecticut	Y	Y	Y	N	Y
Delaware	N	N	N	N	N
D.C.	N	Y	Y	N	Y
Florida	Y	Y	Y	N	N
Georgia	Y	Y	Y	N	Y
Hawaii	Y	N	Y	N	N
Idaho	Y	Y	Y	N	Y
Illinois	N	Y	Y	N	Y
Indiana	N	Y	Y	N	N
Iowa	Y	Y	Y	Y	1/
Kansas	N	Y	Y	Y 5/	Y
Kentucky	N	Y	Y	N	Y
Louisiana	N	N	Y	N	N
Maine	N	N	Y	Y	N
Maryland	N	Y	Y	Y	Y
Massachusetts	N	N	Y	Y	N
Michigan	Y	Y	Y	6/	Y
Minnesota	N	N	N	N	N
Minnesota	N	N	N	N	N
Mississippi	N	N	Y	Y	N
Missouri	Y	Y	Y	N	Y
Montana	Y	Y	Y	Y	N
Nebraska	N	N	N	N	N
Nevada	1/	Y	Y	N	N
New Hampshire	N	N	Y	N	N
New Jersey	N	Y	Y	Y 6/	Y
New Mexico	Y	Y	Y	N	Y
New York	2/	Y	Y	Y	Y
North Carolina	Y	Y	Y	N	Y
North Dakota	N	Y	Y	N	Y
Ohio	Y	Y	Y	N	Y
Oklahoma	1/	1/	Y	N	N
Oregon	Y	Y	Y	N	Y
Pennsylvania	Y	Y	Y	N	Y
Rhode Island	Y	Y	Y	Y	Y
South Carolina	Y	Y	Y	N	Y
South Dakota	N	N	N	N	N
Tennessee	Y	Y	Y	N	Y
Texas	Y	Y	Y	Y	Y
Utah	Y	Y	Y	N	Y
Vermont	N	N	Y	Y	N
Virginia	N	Y	Y	N	Y
Washington	N	N	Y	N	Y
West Virginia	N	Y	Y	Y	Y
Wisconsin	Y	Y	Y	Y	Y
Wyoming	3/	Y	Y	Y	Y

Source: Paul Rodgers, 1979 Annual Report on Utility and Carrier Regulation of the National Association of Regulatory Utility Commissioners (Washington, D.C.: NARUC, 1980) pp. 501-2.

1/ The rules of the gas utilities contain priority of service during outages and curtailments.
2/ New York PSC case 25766 covers emergency regulations governing gas service.
3/ Commission and utilities have produced an emergency operation plan.
4/ Only outside municipal limit.
5/ Municipalities participate voluntarily.
6/ The state has no public gas utilities.

establish priorities for customer classes served by investor-owned utilities, while only 16 commissions have such authority with respect to publicly-owned utilities. The last column of the table indicates that 33 public utility commissions have established standards for attaching new gas customers during shortages.

Most state public utility commissions regulate policies and company practices concerning attachment of new gas customers and loads. Table A-14 shows that gas service upon request is mandated by state law in 24 responding states and is required under public utility commission rules in 30 states. As indicated by columns one and two of table A-14, in only 11 states is gas service upon request not mandated by either state law, commission rules, or both. In 15 states, excluding Hawaii,[1] gas companies can refuse to provide service even when gas is available. This discretion on the part of the gas companies is usually intended to allow them to avoid unreasonable distribution costs.

Column four of table A-14 shows the reported number of gas utilities serving the state ranging from 1 in Maine to 77 in Florida. Special care must be taken in interpreting this figure because some states appear to report only major gas utilities. In most states, almost all the utilities serving each state are currently attaching new customers. The states where a significant number of gas utilities are not attaching new customers are Maryland, Nevada, New Mexico, Pensylvania and Tennessee. Of the 38 states reporting on the existence of waiting lists for new service, 11 states have gas utilities with no waiting lists.

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[1] Information on Hawaii is unavailable.

TABLE A-14

STATE POLICY ON THE ATTACHMENT OF NEW GAS CUSTOMERS AND LOADS BY STATE, 1979

Column Agency	(1) Gas on Request Mandated by State Law	(2) Gas on Request Mandated by Commission Rules	(3) Companies can refuse Service if gas supply is Available	(4) Number of Companies Serving the States	(5) Number of Companies Attaching New Customers/ Loads	(6) Number of Companies With Writing Lists
Alabama	Y	Y	N	1/	5	1/
Alaska	Y	N	N	3	3	0
Arizona	N	Y	N	12	11	2
Arkansas	N	Y	Y 7/	7	4	1/
California	Y	Y	N	3	3	1/
Colorado	Y	Y	N	23	23	23
Connecticut	N	Y	N	6	6	6
Delaware	1/	Y	N	2	2	2
D.C.	N	N	N 8/	1	1	1
Florida	Y	Y	Y	77	77	1/
Georgia	Y	Y	Y	4	4	0
Hawaii	1/	1/	1/	1/	1/	1/
Idaho	Y	Y	N	2	2	0
Illinois	Y	4/	N	7	7	7
Indiana	N	N	Y	46	46	1/
Iowa	N	N	N	11	11	11
Kansas	Y	Y	N	5	5	5
Kentucky	N	N	N	4	1/	4
Louisiana	N	N	Y 9/	42	42	0
Maine	Y	Y	Y	1	1	0
Maryland	1/	1/	Y 9/	11	0	1/
Massachusetts	Y	Y	Y	13	5	5
Michigan	N	Y	Y 10/	10	9	10
Minnesota	Y	Y	N	21	21	21
Mississippi	Y	Y	N	3	3	5
Missouri	N	1/	N	14	1/	1/
Montana	Y	N	N	2	2	1
Nebraska 5/	N	N	N	5/	5/	5/
Nevada	1/	1/	N	3	0	1/
New Hampshire	Y 2/	Y 2/	N	4	4	4
New Jersey	Y	Y	N	4	4	4
New Mexico	1/	1/	N	6	0	1/
New York	N	N	N	14	14	4
North Carolina	Y	Y	N	5	5	0
North Dakota	N	N	N	3	3	1
Ohio	N	N	N	8	8	8
Oklahoma	N	Y	Y 7/	4	4	1/
Oregon	Y	Y	N	3	3	13/
Pennsylvania	N	Y	N	43	10	43
Rhode Island	Y	Y 6/	N	6 11/	6 11/	0
South Carolina	Y 3/	Y 3/	Y 3/	6	6	6
South Dakota	N	N	Y	4	4	4
Tennessee	N	N	Y	7	6	1/
Texas	Y	N	N	59 12/	59	0
Utah	N	Y	Y	2	2	0
Vermont	1/	Y	N	7	7	1
Virginia	N	Y 3/	Y	12	12	0
Washington	Y	Y	N	4	4	0
West Virginia	1/	1/	N	5	1/	5
Wisconsin	Y	Y	N	7	6	3
Wyoming	Y	Y	N	5	5	0

Source: Paul Rodgers, 1979 Annual Report on Utility and Carrier Regulation of the National Association of Regulatory Utility Commissioners (Washington, D.C., NARUC, 1980) pp. 647-648

1/ Not available.
2/ Subject to tariff.
3/ Unless otherwise ruled by the state commission.
4/ Not applicable.
5/ Telephone is the only regulated utility.
6/ Subject to line extension policy.
7/ When unreasonable costs are involved.
8/ Except for reasons other than service such as the cost of the service line.
9/ If don't comply with the distribution company's extension plan.
10/ Must be authorized by the commission.
11/ Each of six operating division of a single gas company are reported as separate companies.
12/ Distribution companies only.
13/ Companies must keep waiting lists on requests for firm service in excess of 300 therms per day.

Most state public utility commissions also have authority to regulate gas cost adjustment clause increases. Table A-15 shows the categories of authority relating to the establishment of automatic adjustment clauses in the tariff, the permission to allow utilities to recover the changes in purchased gas costs through the automatic adjustment clause, and the requirement for a hearing before adjustment clauses can be used to recover changes in purchased gas costs. Forty-six state agencies have the authority to establish these adjustments in tariffs, but only 34 states allow for the use of automatic adjustment clauses by utilities to recover changes in purchased gas costs. A minority of the state agencies, 11, require hearings before adjustment clauses are implemented to recover the changes in purchased gas costs.

Most state public utility commissions prescribe special accounting or reporting requirements for transactions by gas distribution companies with affiliate companies. As table A-16 shows, of the 44 state commissions responding, 28 commissions indicated that they have special accounting requirements that are in accordance with their own system of accounts. Five additional state public utility commissions indicated that they presently have the option of requiring special accounting if the occasion requires. Finally, two state commissions have indicated that they have the authority to require special accounting for transactions with affiliates.

Thirty state commissions indicated that they either had special reporting requirements for transactions with affiliates or that transactions with affiliates must be reported in a utility's annual report. In addition, five commissions indicated that they presently have the option

TABLE A-13

STATE AGENCY AUTHORITY AND PRACTICES CONCERNING GAS COST ADJUSTMENT CLAUSES; BY STATE, 1979

Column Agency	(1) Authority to Establish Automatic Adjustment Clause in Tariff	(2) Allows Automatic Adjustment Clause to Permit Utilities to Recover Changes in Purchased Gas	(3) Requires Adjustment Clause Hearing before Recovery of Changes in Purchased Gas
Alabama	Y	Y	N
Alaska	Y	Y	N
Arizona	Y	Y	N
Arkansas	Y	Y	N
California	Y	N	Y
Colorado	Y	N	Y
Connecticut	N	N	Y
Delaware	Y	N	Y
D.C.	Y	Y	N
Florida	Y	Y	N
Georgia	Y	Y	N
Hawaii	Y	Y	N
Idaho	Y	1/	1/
Illinois	Y	Y	N
Indiana	Y	N	Y
Iowa	Y	Y	N
Kansas	Y	Y	N
Kentucky	Y	N	Y 2/
Louisiana	Y	Y	N
Maine	Y	Y	N
Maryland	Y	Y	N
Massachusetts	Y	N	Y
Michigan	Y	Y	N
Minnesota	Y 3/	Y	N
Mississippi	Y	Y	N
Missouri	Y	Y	N
Montana	N	1/	1/
Nebraska	5/	5/	5/
Nevada	Y	N	Y
New Hampshire	Y	N	Y
New Jersey	Y	N	Y
New Mexico	Y	Y	N
New York	Y	Y	N
North Carolina	N	Y	N
North Dakota	Y	Y	N
Ohio	Y	Y	N
Oklahoma	Y	Y	N
Oregon	Y	1/	1/
Pennsylvania	Y	Y	N
Rhode Island	Y	Y	N
South Carolina	Y	Y	N
South Dakota	Y	Y	N
Tennessee	Y	Y	N
Texas	Y	Y	N
Utah	N	1/	1/
Vermont	Y	Y	N
Virginia	Y	Y	N
Washington	Y	1/	1/
West Virginia	Y	Y	N
Wisconsin	Y	Y	N 4/
Wyoming	Y	N	Y

Source: Paul Rodgers, 1979 Annual Report on Utility and Carrier Regulation of the National Association of Regulatory Utility Commissioners (Washington, D.C.:NARUC, 1980) pp. 403

1/ Not Applicable—no adjustment clause in effect.
2/ No change may be made by any utility except upon twenty (20) days notice to the commission If after examination of the data provided the rate is justified, public hearing is waived and or Order of the Commission the change in rate is made.
3/ The Commission permits the utilities to file rate schedules containing provisions for the automatic adjustment of charges.
4/ The Wisconsin Legislature recently regulated the Attorney General's opinion on the legality of automatic pass through of costs without hearing.
5/ Not Available.

TABLE A-16

STATE POLICY CONCERNING TRANSACTIONS WITH AFFILIATES BY STATE, 1979

Column	(1)	(2)
	State Agency prescribes special requirements for transactions with affiliates	
Agency	Accounting	Reporting
Alabama	Yes.	Investigation by staff.
Alaska	Yes for the Alaska Public Service Commission. Policy not developed for the Alaska Pipeline Commission.	Investigation by staff for the Alaska Public Service Commission
Arizona	No response.	No response.
Arkansas	For system of accounts and annual reports, Same requirements as FERC.	For system of accounts and annual reports. Same requirements as FERC.
California	Accounting requirements same as FERC.	Reporting requirements same as FERC.
Colorado	No.	Reasonableness of affiliate transactions are considered in rate cases.
Connecticut	No.	Service contract charges from affiliates are reported in the utilities annual reports.
Delaware	No response.	No response.
D.C.	Any special accounting treatment it requires.	The Commission can set those reporting requirements necessary to carry out its statutory responsibilities.
Florida	Yes.	Yes.
Georgia	No response.	No response.
Hawaii	Yes.	Must submit consolidating statements with explanation of transactions and basis of allocation of common expenses.
Idaho	No.	No.
Illinois	Approval of all transaction except those specifically excluded by section 8(a) of the Public Utilities Act.	File reports relative to such transactions as the commission may prescribe.
Indiana	Yes.	Yes.
Iowa	Records of transactions must be preserved in the same manner as for the utility. Extraordinary documentation may be required and pricing is subject to greater scrutiny.	Same as FERC.
Kansas	Statute requires full disclosure, Adjustments are made for ratemaking.	Must identify related companies in annual report file all contracts and keep commission fully informed of transaction.
Kentucky	No response.	No response.
Louisiana	Yes, insofar as certain transactions are concerned.	No.
Maine	Only as occasion requires.	Only as occasion requires.
Maryland	Follow requirements of the uniform system of accounts.	Follow requirements of report forms.
Massachusetts	To the extent that they affect the regulated utility adversely.	Requires an abbreviated report from from each affiliate
Michigan	For system of accounts.	Yes, in rate case filing requirements and annual reports
Minnesota	For system of accounts.	Part of Annual report.
Mississippi	No.	No.
Missouri	Yes.	Yes.
Montana	Must be absolutely separate.	All transactions are kept separately.
Nebraska	All transactions deemed necessary.	All transactions deemed necessary
Nevada	No.	No.
New Hampshire	Depends on specific transactions.	Must submit various contracts which affect New Hampshire utilities—such as contracts for services rendered and charged to utility.
New Jersey	Transaction must be reasonable and provide for elimination of unsupportable gains.	Description required to be given in annual report plus supplemental reports if deemed necessary.
New Mexico	No response.	No response.
New York	Companies are required to keep accounts so as to be able to accurately and expeditiously produce statements of all transactions with associates.	Commission has authority under its general powers to require any special reports to keep the commission informed.
North Carolina	The type and dollar amount of the goods and services represented by transactions between the regulated company and its affiliate must be identifiable in the books of account of the regulated company.	Annually the regulated companies must report the type, dollar amount and the name of the affiliate from which goods and services were received.
North Dakota	No prescription.	No prescription.
Ohio	Commission has authority but no standards have been adopted. Not significant in Ohio.	Part of annual report. The commission has authority to require report.
Oklahoma	As required by uniform system of accounts.	As required by uniform system of accounts.
Oregon	Furnish detail of costs and profit between affiliates.	File detail of all transactions showing costs and other pertinent data.
Pennsylvania	No response.	No response.
Rhode Island	Yes.	Yes.
South Carolina	All necessary steps to protect consumers.	Reports and other transaction filed and reviewed by the commission.
South Dakota	Yes.	Yes.
Tennessee	Yes.	Yes.
Texas	Yes.	Yes.
Utah	There are no specific provisions in Utah law but the commission is of the opinion it has adequate authority under the section of the law relating to accounts to prescribe such requirements.	There are no specific provisions in Utah law but the commission is of the opinion it has adequate authority under the section of the law relating to reports to prescribe such requirements.
Vermont	No response.	No response.
Virginia	Yes.	Yes.
Washington	Maintain record of the cost of the services provided by the affiliate and if ascertainable the cost of all items sold to the utility.	All services and things should be provided at cost by the affiliate and the annual reports of the cost thereof are filed with the commission.
West Virginia	As required by the uniform system of accounts.	As required by annual reports.
Wisconsin	Highly intensive.	Yes.
Wyoming	Generally, complete separation of operations with only benefits flowing to utility.	Requirements patterned to facts of each case.

Source: Paul Rodgers, 1979 Annual Report on Utility and Carrier Regulation of the National Association of Regulatory Utility Commissioners (Washington, D.C.: NARUC, 1980) p. 487.

of requiring special reports if the occasion requires. One commission indicated that it has the authority to require special reporting requirements for transactions with affiliates.

While there is broad state agency authority to regulate natural gas production usually this authority rests in state agencies other than the state public utility commissions. Table A-17 shows the categories of authority to regulate. Listed are the volume and rate of production, the spacing of wells, and the rates on well-head contracts. The final column lists the state agencies with authority to regulate in any or all of the previously mentioned areas, where such authority does not rest in the state public utility commission. Six, four, and three state public utility commissions have regulatory authority in production, well-spacing, and well-head contract rates, respectively. In 21 states, agencies other than the state public utility commission have the authority to regulate in any or all of the three areas.

Table A-18 presents a composite picture of selected statistics for all privately-owned gas utilities under state agency jurisdiction. The selected statistics include the yearly average number of intrastate customers (industrial and total); residential information pertaining to average annual use (MCF) and average monthly billing; the original cost value for intrastate plants by plant in service, construction work in progress, and net book costs; and, income statement figures reflecting operating revenue, total operating expenses, net operating income, and net income.

The number of intrastate industrial customers of privately-owned regulated gas utilities was 322,345 in 1979. This represents an average of

TABLE A-17

STATE AGENCY AUTHORITY TO REGULATE NATURAL GAS PRODUCTION BY STATE, 1979

Column Agency	(1) The Agency has the Authority to Regulate: the Volume and Rate of Production	(2) The Agency has the Authority to Regulate: the Spacing of wells	(3) The Agency has the Authority to Regulate: the Rates on well-head contracts	(4) Foregoing Authority Rests with State Agency other than the State Public Utility Commission
Alabama	N	N	N	Oil and Gas Board
Alaska	Y	N	Y	Department of Natural Resources
Arizona	N	N	N	Oil and Gas Conservation Commission
Arkansas	N	N	N	Oil and Gas Commission 1/
California	N	N	N	Division of Oil and Gas 1/
Colorado	N	N	N	Oil and Gas Conservation Commission 3/
Connecticut	N	N	N	
Delaware	N	N	N	
D.C.	N	N	N	Congress of the United States
Florida	N	N	N	Internal Improvement Board
Georgia	N	N	N	
Hawaii	N	N	N	
Idaho	N	N	N	
Illinois	N	N	N	Department of Mines and Minerals 3/
Indiana	N	N	N	Natural Resources Commission and State Board of Health
Iowa	N	N	N	Natural Resources Council
Kansas	Y 4/	Y	N	
Kentucky	N	N	Y 5/	Department of Mines and Minerals
Louisiana	N	N	N	Conservation Department
Maine	N	N	N	
Maryland	N	N	N	
Massachusetts	N	N	N	
Michigan	Y 6/	N	Y 7/	Department of Natural Resources
Minnesota	N	N	N	
Mississippi	N	N	N	Oil and Gas Board
Missouri	N	N	N	
Nebraska	N	N	N	
Nevada	N	N	N	
New Hampshire	N	N	N	
New Jersey	N	N	N	
New Mexico	N	N	N	Oil Conservation Commission 1/
New York	N	Y 8/	N	Department of Environmental Conservation
North Carolina	N	N	N	Department of Natural and Economic Resources
North Dakota	N	N	N	Industrial Commission 1/
Ohio	N	N	N	Department of Natural Resources regulates spacing of wells.
Oklahoma	Y 9/	Y	N	
Oregon	N	N	N	
Pennsylvania	N	N	N	
Rhode Island	Y 10/	N	N	
South Carolina	N	N	N	
South Dakota	N	N	N	
Tennessee	N	N	N	Department of Gas Conservation, Geology Div., Oil and Gas Board
Texas	Y 11/	Y	N	
Utah	N	N	N	The Division of Oil and Gas Conservation 5/
Vermont	N	N	N	
Virginia	N	N	N	

Source: Paul Rodgers, 1979 Annual Report on Utility and Carrier Regulation of the National Regulatory Utility Commissioners (Washington, D.C.:NARUC, 1980) pp. 645.

1/ Authority to regulate the volume and rate of production and the spacing of wells.
2/ Regulates volume and rate of production, with rateable take on a statewide basis and regulated the spacing of wells.
3/ Regulates the spacing of wells and well-head prices.
4/ Rateable take is on a reservior basis. Rate of production is determined by hearings based on market demands.
5/ Some jurisdiction.
6/ Maximum rate of gas well gas production based on percentage of open flow capacity. Oil well gas production, where restricted, based on gas oil ratios. No rateable take for oil well gas production. Rateable take for gas well gas production under standard commission rules, based on formula giving equal weight to open flow capacity and acreage factor. Acreage factor is dependent on size or producing unit and location of well on unit. Majority of gas well gas production is state pro-rated, based on formula giving dominant weight to pay rock volume attributable to producing unit.
7/ Limited to changes in central filed rates for conditions of service.
8/ Well spacing is regulated on fields discovered after October 1963, by New York Department of Environmental Conservation.
9/ Rateable take is on a reservoir and statewide basis. Rate of production is determined by market demand.
10/ LPG and LNG only.
11/ Rateable take is on a reservoir basis.
12/ Authority eliminated by 1976 Wyoming Supreme Court ruling.

TABLE A-18

COMPOSITE OF SELECTED STATISTICS FOR ALL PRIVATELY OWNED GAS UTILITIES UNDER AGENCY JURISDICTION

Column	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
	Intrastate Customers		Residential Statistics		Intrastate Plant (000 omitted)			Intrastate Revenues and Expenses (000 omitted)			
Agency	Industrial	Total	Average Annual Use-MCF	Average Monthly Bill($)	Plant in Service	Construction Work in Progress	Net Book Costs	Operating Revenue	Total Operating Expenses	Net Operating Income	Net Income
Alabama 1/	43	319,709	2/	24.30	162,496	885	120,786	237,340	2/	2/	2/
Arizona	1,096	332,907	71.27	20.62	220,779	8,034	215,313	238,922	225,112	13,810	9,791
Arkansas	234	69,971	109	19.34	37,411	435	39,269	38,179	33,142	5,037	4,396
California	31,831	6,986,262	88	18.88	3,764,019	47,262	2,473,707	4,468,234	4,263,327	204,907	144,621
Colorado	1,093	738,303	134	27.61	399,463	7,178	281,771	431,564	419,317	12,247	11,190
Connecticut 2/											
Delaware	185	76,163	96	32.00	63,985	609	44,949	53,858	48,938	4,920	4,930
D.C.	2/	149,082 3/	1,017 4/	.3743 4/	133,288	2/	96,994	95,166	91,732	3,394	3,394
Florida	45	31,730	2/	2/	207,005	3,876	134,299	149,889	139,162	10,727	6,209
Georgia	671	603,130	89.33	20.89	489,838	2,021	334,902	380,307	352,754	27,553	14,867
Hawaii	2/	33,361	252 4/	23.00	30,150	70	38,197	32,940	28,843	4,097	2,966
Idaho	600	108,039	90	28.92	123,987	148	88,462	144,434	136,162	8,272	3,102
Illinois	346,792	3,211,038	175	43.25	3,090,576	37,388	2,306,867	3,218,388	3,001,232	217,156	2/
Indiana 11/	1,039	440,863 5/	2/	2/	339,961	3,166	274,827	376,877	348,890	27,987	21,292
Iowa 6/	1,373	700,760	144	32.73	413,870	6,905	320,693	615,974	591,357	24,617	2/
Kansas	3,239	667,088	167	23.90	411,932	3,769	291,844	318,753	302,320	16,433	46,366
Kentucky	760	339,223	139.5	27.99	475,203	6,654	263,257	421,254	395,464	25,790	37,392
Louisiana 2/											
Maine 7/	2/	15,000	42	18.90	14,932	107	12,971	8,342	7,511	831	143
Maryland	3,284	1,002,643	99	31.06	879,165	7,980	635,233	696,743	643,661	53,082	146,644
Massachusetts	2,342	932,440	2/	37.38	741,887	3,934	374,961	715,353	662,943	52,410	2/
Michigan 7/	9,375	3,373,602	174.8	38.65	2,429,070	39,613	1,834,756	2,232,072	2,111,977	120,095	69,399
Minnesota	5,505	742,448	130	37.31	513,684	7,386	376,170	607,424	571,774	35,650	25,423
Mississippi 2/											
Missouri	763	1,073,234	130.9	32.50	643,280	2,206	457,465	732,686	692,959	39,727	25,157
Montana	2/	184,852	26	38.53	280,586	2/	2/	182,222	176,738	2/	5,484
Nebraska 8/											
Nevada	20	151,015	93.2	23.15	162,397	13,065	140,211	220,619	206,699	13,920	9,975
New Hampshire	245	46,139	2/	30.12	40,191	137	29,391	30,162	28,474	1,688	859
New Jersey	2/	1,843,693	86.39	24.89	1,307,688	13,501	856,237	1,102,190	1,016,510	85,680	58,308
New Mexico	2/	288,819	103	23.80	2/	2/	2/	377,083	2/	7,404	2/
New York 9/	2/	4,119,238	93.5	30.87	2,395,758	68,587	2,130,345	2,439,743	2,278,896	180,852	840,382*
North Carolina	1,089	333,034	97 D.T.	28.80	345,110	3,009	254,234	343,889	319,166	24,723	14,416
North Dakota	37	82,649	184	38.11	83,076	1,806	38,447	67,512	61,765	5,747	8,933
Ohio	2/	2 693,037	2/	2/	1,311,925	14,748	993,703	2,463,954	2,333,912	130,042	109,883
Oklahoma 2/											
Oregon	623	266,093	2/	31.07	2/	2/	2/	310,924	285,164	25,760	2/
Pennsylvania 2/											
Rhode Island 2/	1,300	183,242	88.7	31.24	106,194	309	78,989	102,404	96,040	6,364	6,276
South Carolina	781	228,706	2/	2/	230,147	2,203	161,632	282,467	266,691	15,776	8,190
South Dakota	2/	93,226	140	30.22	65,186	917	44,463	60,735	57,723	3,012	2,366
Tennessee	1,288	248,727	113.49	34.88	111,334	636	75,724	150,428	143,543	6,885	3,854
Texas	1,368	3,131,923	88.63	21.83	3,430,388	2/	2/	6,891,936	6,699,360	192,376	2/
Utah 10/	625	361,017	170	31.56	424,748	22,030	346,076	261,354	237,150	24,204	25,887
Vermont	25	15,636	2/	36.07	16,105	2/	10,308	17,445	16,378	1,067	902
Virginia	567	426,395	100	30.01	351,296	1,630	221,904	406,914	380,875	26,309	26,099
Washington 2/											
West Virginia	2/	391,696	2/	2/	836,233	2/	2/	429,465	628,216	(198,751)	2/
Wisconsin	2/	1,010,700	137	34.45	875,667	2/	2/	987,121	932,979	54,142	2/
Wyoming	113	128,876	2/	32.00	119,329	2/	2/	167,814	161,013	6,801	2/

Source: Paul Rodgers, *1979 Annual Report on Utility and Carrier Regulation of the National Association of Regulatory Utility Commissioners* (Washington, D.C.: NARUC, 1980) pp. 636-639.

1/ Data for Alabama Gas Corporation
2/ Not Available
3/ Meters.
4/ Therm.
5/ No information on 3 Class D companies.
6/ Fiscal year ended June 30, 1979.
7/ Fiscal year ended September 30, 1979.
8/ Not applicable.
9/ Composite of statistics for all Class A and B privately owned gas utilities under agency jurisdiction (systemwide). *Please note that this statement is a composite of fourteen companies - seven companies which sell gas only and seven companies which sell gas, electricity, and, for two companies, steam also. The figures shown are gas only, with the exception of the starred item, which is a total figure.
10/ Approximately 7% of the "Plant" figures represent Wyoming plant; company does not segregate plant by state. Approximately 8% of "Revenues" represents Wyoming revenue. The major company, Mountain Fuel Supply Co., does not segregate expenses by state. Income taxes and other items.
11/ Statistics have been compiled from 10 A-B, 6 C and 9 D private gas utilities.

10,070 for the 32 states responding. The number of intrastate customers (residential, industrial, and other) served by privately-owned regulated gas utilities was 37,919,450 in 1979; and the average is 881,848 customers for the 43 states responding in this category.

The range of average annual residential gas usage in 1979 was from 175 MCF in Illinois to 25 MCF in Hawaii. The mean gas usage was 112 MCF. The reported average monthly residential bill in 1979 ranged from a low of $19.34 in Arkansas to a high of $43.25 for Illinois.

Columns 5, 6, 7 show the plant in service, construction work in progress, and the net book costs of intrastate plant. Columns 8, 9, 10, and 11 show the operating revenue, total operating expense, net operating income, and net income, respectively.

Finally, the first two columns of table A-19 contain information on the supplemental gas supply pricing practices in each state[1] with column 1 showing that 43 states use roll-in pricing; nine use some form of incremental price, and eight states use both. Many states that used incremental pricing in 1979 restricted its use to special cases such as emergency gas purchases.

The last five columns of table A-19 show 1979 gas prices and alternative fuel prices in cents per them. Number 2 oil prices, number 6 oil prices, and propane prices are converted to an equivalent number of cents per therm. In 1979, the average price across the states for residential gas was 35.2 ¢/therm; and for industrial gas customers 30.8 ¢/therm. The price range across the states for number two oil was 25 to

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[1] Excluding Delaware (not available) and Nebraska (not applicable).

TABLE A-19

SUPPLEMENTAL GAS SUPPLY PRICING PRACTICES AND AVERAGE FUEL PRICES FOR SAMPLE URBAN AREAS

Column Agency	(1) At least part of the Supplemental Gas Supply is Priced 1/ Using a Roll-in	(2) At least part of the Supplemental Gas Supply is Priced 1/ Incrementally	(3) Residential Gas Prices (c/Therm)	(4) Industrial Gas Prices (c/Therm)	(5) No. 2 Oil (c/Therm)	(6) No. 6 Oil (c/Therm)	(7) Propane (c/Therm)
Alabama	Y	Y	33.34	24.56	30.30	20 to 22	35 to 45
Alaska	2/	2/	2/	2/	2/	2/	2/
Arizona	Y	Y	29.53	21.39	25.7	2/	59.2
Arkansas	Y	N	2/	2/	2/	2/	2/
California	Y	N	25.70	35.45	28.9	25.2	44 to 47
Colorado	Y	N	32.27	2/	51.8	35.0	48.4
Connecticut	Y	N	47.38	43.25	31.38	26.74	2/
Delaware	2/	2/	43.40	36.90	38.90	2/	59.5
D.C.	Y	N	2/	2/	2/	2/	2/
Florida	Y	N	31.43	26.98	27.40	26.40	35.6 to 70.8
Georgia	Y	Y	27.70	25.15	32.45	2/	47.25
Hawaii	N	N	2/	2/	2/	2/	2/
Idaho	Y	N	37.46	34.32	2/	2/	47 to 49
Illinois	Y	N	29.68	24.29	35.20	26 to 28	33.5
Indiana	Y	N	28.90	26.10	62.30	37.94	58.6
Iowa	N	N	28.09	23.09	68.40	28.0	58.84
Kansas	Y	N	22.64	20.19	58.40	24.19	60.88
Kentucky	Y	3/	26.02	20.16	33.9	2/	46.7
Louisiana	Y	N	24.68	20.74	32.1	23.5	40.8
Maine	Y	N	53.19	46.26	37.4to 39.7	2/	34.6
Maryland	Y	N	38.96	35.58	46.47	34.3	35.72
Massachusetts	N	N	43.38	39.95	43.17	24.13	64.52
Michigan	Y	N	28.53	42.55 5/	36.	22.3	43.1
Minnesota	Y	Y	28.53	24.19	37.4	22.1 to23.5	40.8
Mississippi	Y	N	27.90	24.05	28.9	18.	44.8
Missouri	Y	N	33.36	28.79	35.3	2/	2/
Montana	Y	N	24.20	21.31	28.7	2/	57.2
Nebraska	4/	4/	23.71	21.00	28.1	17.9	33.5 to 38.7
Nevada	Y	N	20.53	17.20	24.7 to 26.1	2/	67.9
New Hampshire	N	N	47.3	40.6	74.1	2/	2/
New Jersey	Y	N	41.82	36.09	31.6 to 40.2	30 to 31.4	56.6
New Mexico	Y	N	32.08	29.33	2/	2/	2/
New York	Y	N	62.49	49.79	66.3 to 72.	39.6to58.1	75.6 to105
North Carolina	Y	N	37.55	28.35	60.7	35.8	69.1
North Dakota	Y	N	51.50	47.28	70.0	34.5	2/
Ohio	Y	Y	37.7	30.59	50.0	to 30.6	49.2 to74.8
Oklahoma	Y	N	48.26	20.40	32.4 to 33.8	23.3to23.9	38.7to41.8
Oregon	Y	N	47.69	45.30	25.	2/	40.
Pennsylvania	Y	N	2/	2/	2/	2/	2/
Rhode Island	Y	Y	56.01	51.31	72.	52.	65 to 75
South Carolina	Y	Y	29.53	24.03	26.6 to 31	16.9 to 23.5	11.8to18
South Dakota	Y	N	28.73	2/	65.0	2/	59.8 to 61.9
Tennessee	Y	Y	24.11	25.56	29.2	2/	33.5 to 44.5
Texas	Y	N	25.93	25.84	2/	2/	2/
Utah	Y	N	31.57	22.79	60.76	2/	67.43
Vermont	N	N	41.60	34.18	40.3 to 41.8	2/	41.8 to 68
Virginia	Y	Y	41.4	31.3	70	50	62
Washington	Y	N	48.17	41.24	86	2/	73.2
West Virginia	Y	N	26.56	25.48	31.7 to 35.3	19.4 to 24.8	27. to 37.6
Wisconsin	Y	N	33.92	30.25	65 to 58	32 to 34.3	39.3 to 47
Wyoming	Y	N	2/	2/	27.2 to 31	18.6 to 22	42.5to5356

Source: Paul Rodgers, 1979 Annual Report on Utility and Carrier Regulation of the National Association of Regulatory Utility Commissioners (Washington, D.C. :NARUC, 1980) pp. 661-4.

1/ Supplemental gas supply include synthetic, liquid and pertoleum gas, local field gas. emergency gas, ethane, storage, exploration and development and other.
2/ Not available.
3/ Only for industrial customers
4/ Telephone is the only regulated utility.
5/ 22.9 c/Therm for 5,000 Therms.

72 ¢/therm and 16.9 to 58.1 ¢/therm for number 6 oil. Propane showed the widest range across the states of 11.8 to 105 ¢/therm in 1979, with most of states falling in the 40 to 70 ¢/therm range.